

AIR QUALITY PERMIT

Issued To: Rocky Mountain Ethanol, LLC
490 N. 31st St.
Billings, MT 59101

Permit #3402-00
Application Complete: 09/29/05
Preliminary Determination Issued: 10/03/05
Department Decision Issued: 11/03/05
Permit Final: 11/19/05
AFS #003-0033

An air quality permit, with conditions, is hereby granted to Rocky Mountain Ethanol, LLC (RME), pursuant to Sections 75-2-204 and 211, Montana Code Annotated (MCA), as amended, and Administrative Rules of Montana (ARM) 17.8.740, *et seq.*, as amended, for the following:

Section I: Permitted Facilities

A. Permitted Equipment

RME's proposed facility is a fuel-grade ethanol production plant. The new facility will be a corn and barley dry mill plant designed for up to 80 million gallons per year (MMG/yr) of ethanol production. By-products will include carbon dioxide and Distillers Dried Grains and Solubles (DDGS) animal feed. A complete list of permitted equipment for the ethanol production facility is contained in the permit analysis.

B. Plant Location

RME submitted Permit Application #3402-00 to construct a fuel-grade ethanol production facility near Hardin, Montana, in the SW $\frac{1}{4}$ of Section 12, Township 1 South, Range 33 East, Big Horn County, Montana.

Section II: Conditions and Limitations

A. General Plant Requirements

1. RME may not cause or authorize to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, emissions that exhibit an opacity of 20% or greater averaged over six consecutive minutes (ARM 17.8.304).
2. RME may not cause or authorize the production, handling, transportation, or storage of any material unless reasonable precautions are taken to control emissions of airborne particulate matter. Such emissions shall not exhibit an opacity of 20% or greater averaged over six consecutive minutes (ARM 17.8.308).
3. RME may not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions, such as flushing paved sources with water, to control emissions of airborne particulate matter (ARM 17.8.308).
4. RME shall treat all unpaved portions of the haul roads, access roads, parking lots, or general plant area with water and/or chemical dust suppressant as necessary to maintain compliance with the reasonable precautions limitation in Section II.A.3 (ARM 17.8.749).

B. Individual Conditions for Sources:

1. Fermentation Process

- a. RME shall install, operate, and maintain a wet scrubber to control Volatile Organic Compounds (VOC) emissions on the fermentation process (ARM 17.8.752).
- b. VOC emissions shall be 95% controlled by the wet scrubber for VOC concentrations greater than 200 ppm; or if inlet concentration is less than 200 ppm of VOC, then VOC emissions shall not exceed 20 ppm (ARM 17.8.752).

2. Grain Handling

- a. RME shall install, operate, and maintain a baghouse on the grain handling system (ARM 17.8.752).
- b. Emissions may not exhibit an opacity of 20% or greater averaged over six consecutive minutes (ARM 17.8.304).
- c. PM/PM₁₀ emissions from the baghouse may not exceed 0.004 grains/dry standard cubic foot (gr/dscf) (ARM 17.8.752).
- d. RME shall conduct an initial EPA Method 9 opacity test on the grain handling system to comply with the 20% opacity limitation contained in Section II.B.2.b with 365 days after initial source start up (ARM 17.8.105 and ARM 17.8.749).
- e. All compliance source tests must be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.749 and ARM 17.8.106).

3. Distillation

- a. RME shall install, operate, and maintain a wet scrubber on the distillation process (ARM 17.8.752).
- b. VOC emissions shall be 95% controlled by the wet scrubber for VOC concentrations greater than 200 ppm; if inlet concentration is less than 200 ppm of VOC, then VOC emissions shall not exceed 20 ppm (ARM 17.8.752).

4. DDGS Dryer and Cooler

RME shall route emissions from the DDGS dryer and the DDGS cooler to the fluidized bed boiler for use as combustion air (ARM 17.8.752).

5. Coal Handling

- a. RME shall install, operate, and maintain a baghouse on the coal handling system prior to being fed to the boiler (ARM 17.8.752).
- b. PM/PM₁₀ emissions from the baghouse that controls the coal handling system shall not exceed 0.01 gr/dscf (ARM 17.8.752).
- c. RME shall use mist spraying during receiving of coal (ARM 17.8.752).

6. Truck Traffic

- a. RME shall pave plant roads to limit PM/PM₁₀ emissions from vehicle traffic (ARM 17.8.752).
- b. RME shall not have vehicle traffic between midnight and 4:00 am to control PM/PM₁₀ emissions from vehicle traffic (ARM 17.8.752).

7. Pulverized Coal (PC)-Fired Coal Boiler and Fluidized Bed Combustor (FBC)

- a. RME shall install, operate, and maintain a baghouse on the PC-fired boiler and fluidized bed combustor (ARM 17.8.752).
- b. PM/PM₁₀ emissions from the boilers shall not exceed the following (ARM 17.8.752):
 - i. From the PC-fired boiler: 0.015 lb/MMBtu
 - ii. From the FBC: 0.026 lb/MMBtu
- c. VOC emissions shall not exceed 0.0034 lb/MMBtu on the coal-fired boilers (ARM 17.8.752).
- d. NO_x emissions from the boilers shall not exceed the following (ARM 17.8.749):
 - i. From the PC-fired boiler: 0.15 lb/MMBtu
 - ii. From the FBC: 0.1 lb/MMBtu
- e. RME shall install Selective Non-Catalytic Reduction (SNCR) with overfire air and ammonia injection to control NO_x on the PC-fired boiler and the FBC (ARM 17.8.752).
- f. CO emissions from the boilers shall not exceed the following (ARM 17.8.752):
 - i. From the PC-fired boiler: 0.14 lb/MMBtu
 - ii. From the FBC: 0.11 lb/MMBtu
- g. SO₂ emissions from the boilers shall not exceed the following (ARM 17.8.752):
 - i. From the PC-fired boiler: 0.13 lb/MMBtu
 - ii. From the FBC: 0.09 lb/MMBtu
- h. RME shall install a spray drying system and a baghouse to control SO₂ emissions from the PC-fired boiler and the FBC (ARM 17.8.752).

8. Natural Gas Boilers

- a. VOC emissions may not exceed 0.0054 lb/MMBtu on the natural gas boilers (ARM 17.8.752).
- b. RME shall limit PM/PM₁₀ emissions from the natural gas boilers to less than 0.0075 lb/MMBtu (ARM 17.8.752).
- c. RME shall install Low NO_x burners to control NO_x emissions on the natural gas boiler (ARM 17.8.752).

- d. Total NO_x emissions from the natural gas boilers shall not exceed 0.05 lb/MMBtu (ARM 17.8.752).
- e. RME shall use good combustion practices to maintain CO emissions from the natural gas boilers to less than 0.084 lb/MMBtu (ARM 17.8.752).
- f. All compliance source tests must be conducted in accordance with the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).

9. Diesel Generator

- a. RME shall limit hours of the generator to 500 hours/year (ARM 17.8.752).
- b. PM/PM₁₀ emissions from the diesel generator shall not exceed 0.0007 lb/hp-hr (ARM 17.8.752).
- c. NO_x emissions from the emergency generator shall not exceed 0.013 lb/hp-hr (ARM 17.8.752).

10. Cooling Towers

RME shall install, operate, and maintain cellular mist eliminators on the cooling towers that limit total PM₁₀ emissions to no more than 0.005% of circulating water flow (ARM 17.8.752).

11. Ethanol Loadout to Trucks and Railcars and Fugitive Sources (i.e. valves, flanges, pumps)

RME shall install, operate, and maintain a flare to control VOC emissions on the ethanol loadout system (ARM 17.8.752).

12. Storage Tanks

RME shall install, operate, and maintain the following tanks with internal floating roofs that meets the standards specified in 40 CFR Part 60, Subpart Kb-Standards of Performance for Volatile Organic Liquid Storage Vessels (ARM 17.8.752, ARM 17.8.3340, and 40 CFR Part 60, Subpart Kb):

Denaturant Tank
Denaturant Ethanol Tank 1
Denaturant Ethanol Tank 2
Shift Tank 1
Shift Tank 2

C. Testing Requirements

- 1. Compliance with the PM/PM₁₀ limits for the grain handling system and the hammermilling process shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every five-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749).

2. Compliance with the PM/PM₁₀ emission limits for the PC-fired boiler/FBC, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).
3. Compliance with the VOC emission limits for the PC-fired boiler/FBC, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).
4. Compliance with the NO_x emission limits for the PC-fired boiler/FBC, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).
5. Compliance with the CO emission limits for the PC-fired boiler/FBC, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).
6. Compliance with the SO₂ emission limits for the PC-fired boiler/FBC, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, ARM 17.8.752).
7. Compliance with the VOC emission limits for the natural gas-fired boilers, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749).
8. Compliance with the NO_x emission limits for the natural gas-fired boilers, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an annual or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749).
9. Compliance with the VOC emission limits for the ethanol loadout, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue annually or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749, 40 CFR Part 60, Subpart Db).

10. Compliance with the VOC emission limits for the distillation process, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every five-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749).
11. Compliance with the PM/PM₁₀ emission limits for the coal handling baghouse, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every five-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749).
12. Compliance with the VOC emission limits for the flare, shall be determined by an initial performance source test conducted within 60 days of achieving the maximum production rate at which the affected facility will be operated but not later than 180 days after initial startup. After the initial source test, testing shall continue on an every five-year basis or according to another testing/monitoring schedule as may be approved by the Department (ARM 17.8.105, ARM 17.8.749).
13. RME shall meet all compliance and performance test methods and procedures, emission monitoring, and reporting and recordkeeping requirements as specified in 40 CFR 60, Subpart Db, Standards of Performance for Industrial Commercial – Institutional Steam Generating Units (ARM 17.8.340, and 40 CFR Part 60, Subpart Db).
14. RME shall meet all compliance and performance test methods and procedures, emission monitoring, and reporting and recordkeeping requirements as specified in 40 CFR 60, Subpart Dc, Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units (ARM 17.8.340 and 40 CFR Part 60, Subpart Dc).
15. RME shall comply with the testing procedures, reporting and recordkeeping, and monitoring of operation requirements for these sources as specified in 40 CFR Part 60, NSPS, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels (ARM 17.8.340 and 40 CFR Part 60, Subpart Kb).
16. All compliance source tests shall conform to the requirements of the Montana Source Test Protocol and Procedures Manual (ARM 17.8.106).
17. The Department may require further testing (ARM 17.8.105).

D. Operational Reporting and Recordkeeping Requirements:

1. RME shall supply the Department with annual production information for all emission points, as required by the Department, in the annual emission inventory request. The request will include, but is not limited to, all sources of emissions identified in the emission inventory contained in the permit analysis and sources identified in Section I of the permit analysis.

Production information shall be gathered on a calendar-year basis and submitted to the Department by the date required in the emission inventory request. Information shall be in units as required by the Department. This information may be used to calculate operating fees, based on actual emissions from the facility, and/or to verify compliance with permit limitations (ARM 17.8.505).

2. RME shall notify the Department of any construction or improvement project conducted pursuant to ARM 17.8.745 that would include a change in control equipment, stack height, stack diameter, stack flow, stack gas temperature, source location, or fuel specifications, or would result in an increase in source capacity above its permitted operation or the addition of a new emission unit. The notice must be submitted to the Department, in writing, 10 days prior to start up or use of the proposed de minimis change, or as soon as reasonably practicable in the event of an unanticipated circumstance causing the de minimis change, and must include the information requested in ARM 17.8.745(1)(d) (ARM 17.8.745).
3. All records compiled in accordance with this permit must be maintained by RME as a permanent business record for at least five years following the date of the measurement, must be available for inspection by the Department, and must be submitted to the Department upon request (ARM 17.8.749).

E. CEMS Monitoring Requirements

1. RME shall install, calibrate, maintain, and operate and maintain a CEMS for the following:
 - a. A CEMS for the measurement of SO₂ shall be operated on the PC-fired boiler/FBC stack (ARM 17.8.749 and 40 CFR 60, Subparts Db and Dc).
 - b. A CEMS for the measurement of NO_x shall be operated on the PC-fired boiler/FBC stack (ARM 17.8.749 and 40 CFR 60, Subparts Db and Dc).
 - c. A COMS for the measurement of opacity shall be operated on the PC-fired boiler/FBC stack (ARM 17.8.749 and 40 CFR 60, Subparts Db and Dc).
2. All continuous monitors required by this permit and by 40 CFR Part 60 shall be operated, excess emissions reported, and performance test conducted in accordance with the requirements of 40 CFR Part 60, Subpart A; 40 CFR Part 60, Subpart Db; 40 CFR 60, Appendix B (Performance Specification #1, #2, and #3) (ARM 17.8.749).
3. On-going quality assurance requirements for the gas CEMS must conform to 40 CFR Part 60, Appendix F (ARM 17.8.749).
4. RME shall maintain a file of all measurements from the CEMS, and performance testing measurements; all CEMS performance evaluations; all CEMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The file shall be retained on site for at least five years following the date of such measurements and reports. RME shall supply these records to the Department upon request (ARM 17.8.749).
5. RME shall maintain a file of all measurements from the COMS, and performance testing measurements; all COMS performance evaluations; all COMS or monitoring device calibration checks and audits; and adjustments and maintenance performed on these systems or devices, recorded in a permanent form suitable for inspection. The file shall be retained on site for at least five years following the date of such measurements and reports. RME shall supply these records to the Department upon request (ARM 17.8.749).

E. Notification:

1. RME shall provide the Department with written notification of the following dates within the specified time periods (ARM 17.8.749):
 - a. Commencement of construction of the PC-fired boiler/FBC within 30 days after commencement of construction;
 - b. Anticipated start-up date of the PC-fired boiler/FBC, postmarked not more than 60 days nor less than 30 days prior to start up;
 - b. Actual start-up date of the PC-fired boiler/FBC, postmarked within 15 days after the actual start-up date;
 - c. Commencement of construction of the natural gas-fired boilers within 30 days after commencement of construction;
 - d. Anticipated start-up date of the natural gas-fired boilers, postmarked not more than 60 days nor less than 30 days prior to start-up; and
 - e. Actual start-up date of the natural gas-fired boilers, postmarked within 15 days after the actual start-up date.
2. RME shall supply the Department with the final overall plot plan showing the location, dimensions, and heights of the structures at the facility, within 15 days of completing the final plot plan. If the final plot plan varies significantly from the preliminary plot plan, RME may have to apply for a modification to Permit #3402-00 (ARM 17.8.749).

Section III: General Conditions

- A. Inspection – RME shall allow the Department’s representatives access to the source at all reasonable times for the purpose of making inspections or surveys, collecting samples, obtaining data, auditing any monitoring equipment (CEMS, CERMS) or observing any monitoring or testing, and otherwise conducting all necessary functions related to this permit.
- B. Waiver – The permit and the terms, conditions, and matters stated herein shall be deemed accepted if RME fails to appeal as indicated below.
- C. Compliance with Statutes and Regulations – Nothing in this permit shall be construed as relieving RME of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.* (ARM 17.8.756).
- D. Enforcement – Violations of limitations, conditions and requirements contained herein may constitute grounds for permit revocation, penalties or other enforcement action as specified in Section 75-2-401, *et seq.*, MCA.
- E. Appeals – Any person or persons jointly or severally adversely affected by the Department’s decision may request, within 15 days after the Department renders its decision, upon affidavit setting forth the grounds, therefore, a hearing before the Board of Environmental Review (Board). A hearing shall be held under the provisions of the Montana Administrative

Procedures Act. The filing of a request for a hearing does not stay the Department's decision, unless the Board issues a stay upon receipt of a petition and a finding that a stay is appropriate under Section 75-2-211(11)(b), MCA. The issuance of a stay on a permit by the Board postpones the effective date of the Department's decision until conclusion of the hearing and issuance of a final decision by the Board. If a stay is not issued by the Board, the Department's decision on the application is final 16 days after the Department's decision is made.

- F. Permit Inspection – As required by ARM 17.8.755, Inspection of Permit, a copy of the air quality permit shall be made available for inspection by the Department at the location of the source.
- G. Permit Fee – Pursuant to Section 75-2-220, MCA, as amended by the 1991 Legislature, failure to pay the annual operation fee by RME may be grounds for revocation of this permit, as required by that section and rules adopted thereunder by the Board.
- H. Construction Commencement – Construction must begin within 18 months of permit issuance and proceed with due diligence until the project is complete or the permit shall be revoked (ARM 17.8.762).

Permit Analysis
Rocky Mountain Ethanol, LLC
Permit #3402-00

I. Introduction/Process Description

A. Permitted Equipment

Rocky Mountain Ethanol, LLC (RME) proposed to construct and operate a fuel-grade ethanol production facility near Hardin, Montana, in the SW¼ of Section 12, Township 1 South, Range 33 East, Big Horn County, Montana. The following equipment is permitted for this facility:

<u>ID #</u>	<u>Emission Point</u>
EU01	Grain Receiving Baghouse
EU02	Grain Handling
EU03	Hammer Mill Process
EU04	Hammer Mill Process
EU05	Fermentation/Distillation Process
EU06	Emergency Generator
EU07	Pulverized Coal (PC) Boiler/Fluidized Bed Combustor (FBC)
EU08	Distillers Dried Grains and Solubles (DDGS) Handling
EU09	Ethanol Loadout Flare (trucks)
EU10	Ethanol Loadout (railcar)
EU11	Vent Gas Process
EU12	Auxiliary Boilers
EU13	Coal Handling Baghouse
TK01	Shift Tank 1
TK02	Shift Tank 2
TK03	Denaturant Tank
TK04	Denatured Ethanol Tank 1
TK05	Denatured Ethanol Tank 2
FS01	Uncaptured Grain
FS02	DDGS Storage Building
FS03	Uncaptured DDGS
FS04	Equipment Leaks
FS05	Truck Traffic
FS06	Cooling Towers
FS07	Coal Handling Fugitives
FS08	Limestone Handling Fugitives
FS09	Fly Ash Loadout Fugitives

B. Source Description

Emission sources at RME will include grain handling and processing, coal handling and processing, fermentation, distillation, drying, coal and natural gas and fuel oil combustion (burned in the PC-boiler, the fluidized bed combustor, auxiliary boilers, emergency generator), liquid storage tanks, and fugitive emissions.

The basis for production of ethanol is to convert cornstarch to sugars and then convert the sugars to ethanol. The facility is proposing to receive corn and barley by truck and rail. The corn will be stored in two storage silos and the barley in one prior to processing. The grain

will be ground by hammermilling and conveyed to the process area. Water will then be added to the milled corn to create a slurry. The slurry will be cooked, liquefacted with enzymes, and the resultant mash cooled. The mash will be mixed with yeast and more enzymes in a fermenter. After adequate fermentation, the resultant liquid (beer) will contain 10%-15% ethanol by weight. The beer will distill in a distillation process; the resultant product is 95% ethanol and 5% water (190-proof) and whole stillage consisting of solids and water. Using molecular sieves, the remaining 5% water will be removed from the product resulting in 100% ethanol (200-proof). The product will then be combined with 5% natural gasoline and sold as near 200-proof denatured ethanol.

The denatured ethanol will be shipped via tanker truck and rail car. The whole stillage will be centrifuged to remove the water. The water will be evaporated until a syrup remains. The syrup will be combined with the centrifuged wet spent grain and dried in a hot air fired dryer. The dried spent grain will then be conveyed by a cooling conveyor to be stored in an enclosed storage building. The resulting saleable spent grain by-product is sold as DDGS. The DDGS will then be loaded into trucks and railcars for distribution.

Heat for the DDGS dryers will come from a non-contact heat exchanger that utilizes the thermal energy from the FBC exhaust to heat ambient air. The heated air (non-exhaust) will be routed through the dryers and cooler and then will be routed through the hot gas heater as combustion air, thus allowing for thermal oxidation of the process emissions from the drying operation. The FBC exhaust will combine with a 310 MMBtu coal boiler exhaust after both streams have gone through Selective Non-Catalytic Reduction (SNCR). This combined stream will then go through a spray dryer and baghouse prior to leaving the stack.

II. Applicable Rules and Regulations

The following are partial explanations of some applicable rules and regulations that apply to the facility. The complete rules are stated in the Administrative Rules of Montana (ARM) and are available upon request from the Department of Environmental Quality (Department). Upon request, the Department will provide references for locations of complete copies of all applicable rules and regulations or copies where appropriate.

A. ARM 17.8, Subchapter 1, General Provisions, including, but not limited to:

1. ARM 17.8.101 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.
2. ARM 17.8.105 Testing Requirements. Any person or persons responsible for the emission of any air contaminant into the outdoor atmosphere shall, upon written request of the Department, provide the facilities and necessary equipment, including instruments and sensing devices, and shall conduct tests, emission or ambient, for such periods of time as may be necessary using methods approved by the Department. The Department determined that initial testing is necessary for the grain handling and hammermilling baghouses; the PC-fired boiler/FBC; the natural gas-fired boilers; the ethanol loadout; and the coal-handling baghouse, and that every year testing is required for the PC-boiler and the natural gas boilers.
3. ARM 17.8.106 Source Testing Protocol. The requirements of this rule apply to any emission source testing conducted by the Department, any source, or other entity as required by any rule in this chapter, or any permit or order issued pursuant to this chapter, or the provisions of the Clean Air Act of Montana, 75-2-101, *et seq.*, Montana Code Annotated (MCA).

RME shall comply with all requirements contained in the Montana Source Test Protocol and Procedures Manual including, but not limited to, using the proper test methods and supplying the required reports. A copy of the Montana Source Test Protocol and Procedures Manual is available from the Department upon request.

4. ARM 17.8.110 Malfunctions. (2) The Department must be notified promptly by telephone whenever a malfunction occurs that can be expected to create emissions in excess of any applicable emission limitation, or to continue for a period greater than 4 hours.
5. ARM 17.8.111 Circumvention. (1) No person shall cause or permit the installation or use of any device or any means that, without resulting in reduction in the total amount of air contaminant emitted, conceals or dilutes an emission of air contaminant that would otherwise violate an air pollution control regulation. (2) No equipment that may produce emissions shall be operated or maintained in such a manner that a public nuisance is created.

B. ARM 17.8, Subchapter 2, Ambient Air Quality, including, but not limited to:

1. ARM 17.8.210 Ambient Air Quality Standards for Sulfur Dioxide
2. ARM 17.8.211 Ambient Air Quality Standards for Nitrogen Dioxide
3. ARM 17.8.212 Ambient Air Quality Standards for Carbon Monoxide
4. ARM 17.8.213 Ambient Air Quality Standard for Ozone
5. ARM 17.8.220 Ambient Air Quality Standard for Settled Particulate Matter
6. ARM 17.8.221 Ambient Air Quality Standard for Visibility
7. ARM 17.8.223 Ambient Air Quality Standard for PM₁₀

RME must maintain compliance with the applicable ambient air quality standards.

C. ARM 17.8, Subchapter 3, Emission Standards, including, but not limited to:

1. ARM 17.8.304 Visible Air Contaminants. This rule requires that no person may cause or authorize emissions to be discharged into the outdoor atmosphere from any source installed after November 23, 1968, that exhibit an opacity of 20% or greater averaged over six consecutive minutes.
2. ARM 17.8.308 Particulate Matter - Airborne. (1) This rule requires an opacity limitation of 20% for all fugitive emission sources and that reasonable precautions be taken to control emissions of airborne particulate. (2) Under this rule, RME shall not cause or authorize the use of any street, road, or parking lot without taking reasonable precautions to control emissions of airborne particulate matter.
3. ARM 17.8.309 Particulate Matter - Fuel Burning Equipment. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter caused by the combustion of fuel in excess of the amount determined by this section.
4. ARM 17.8.310 Particulate Matter - Industrial Processes. This rule requires that no person shall cause, allow, or permit to be discharged into the atmosphere particulate matter in excess of the amount set forth in this section.
5. ARM 17.8.322 Sulfur Oxide Emissions - Sulfur in Fuel. Commencing July 1, 1971, no person shall burn any gaseous fuel containing sulfur compounds in excess of 50 grains per 100 cubic feet of gaseous fuel, calculated as hydrogen sulfide at standard conditions.

6. ARM 17.8.324 Hydrocarbon Emissions- Petroleum Products. No person shall load or permit the loading of gasoline into any stationary tank with a capacity of 250 gallons or more from any tank truck or trailer, except through a permanent submerged fill pipe, unless such tank is equipped with a vapor loss control device as described in (1) of this rule. This rule applies to the gasoline storage tank, but 40 CFR 60, Subpart Kb is more stringent and supersedes this rule.
7. ARM 17.8.340 Standard of Performance for New Stationary Sources. The owner or operator of any stationary source or modification, as defined and applied in 40 CFR Part 60, shall comply with the standards and provisions of 40 CFR Part 60.

40 CFR 60, Subpart D - Standards of Performance for Fossil Fuel Fired Steam Generators applies to the natural gas boilers because it has a heat input capacity greater than 100 MMBtu/hr, are fired with a fossil fuel, and produces steam. Although the DDGS Dryer also has a heat input capacity greater than 100 MMBtu/hr and is fired with a fossil fuel, it does not produce steam; therefore, it is excluded from Subpart D.

40 CFR 60, Subpart Db - Standards of Performance for Industrial Commercial-Institutional Steam Generating Units applies to the coal boiler because it has a heat input capacity greater than 100 MMBtu/hr. Although the DDGS Dryer also has a heat input capacity greater than 100 MMBtu/hr, it is excluded from Subpart Db according to an EPA memo dated November 17, 1992. The memo states that, "Subparts Db and Dc do not apply to process dryers or kilns," of which the DDGS Dryer is a process dryer.

40 CFR 60, Subpart Dc – Standards of Performance for Small Industrial, Commercial, and Institutional Steam Generating Units applies to the two natural gas boilers and the fluidized bed combustor since the total heat input to each piece of equipment is between 10 and 100 MMBtu/hr. Only the coal burning fluidized bed combustor is subject to limitations in Subpart Dc. The other equipment is not subject to limitations because they will burn natural gas only. This equipment will, however, be subject to the monitoring and recordkeeping requirements identified in NSPS Subpart Dc.

40 CFR 60, Subpart Kb - Standards of Performance for Volatile Organic Liquid Storage Vessels applies to the two 200-proof ethanol tanks, the denaturant tank, and the two denatured ethanol tanks because they each have a storage capacity greater than 151 cubic meters and contain VOCs with a maximum true vapor pressure greater than 3.5 kiloPascals (kPa).

40 CFR 60, Subpart DD - Standards of Performance for Grain Elevators does not apply to the RME facility. Subpart DD applies only to grain terminal elevators or grain storage elevators, both of which are defined in part by storage capacity. RME's grain storage units are sized well below the defined threshold capacities.

40 CFR 60, Subpart VV - Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry applies to this facility because the facility produces ethanol (a listed chemical) as a final product and operates equipment (i.e., pumps, compressors, pressure relief devices, sampling connection systems, open-ended valves or lines, valves, and flanges) that contains or contacts process fluids that are at least 10% VOC by weight.

40 CFR 60, Subpart NNN - Standards of Performance for Volatile Organic Compounds Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations does not apply to the RME facility. The facility is not subject because it manufactures ethanol using biomass rather than a synthetic process.

40 CFR 60, Subpart RRR - VOC Emissions from SOCMI Reactor Processes does not apply to the RME facility. The facility is not subject because it manufactures ethanol using biomass rather than a synthetic process.

8. ARM 17.8.342 Emission Standards for Hazardous Air Pollutants for Source Categories. This rule incorporates, by reference, 40 CFR Part 63, NESHAP for Source Categories. Since the emissions of Hazardous Air Pollutants (HAPs) from the RME facility are less than 10 tons per year for any individual HAP and less than 25 tons per year for all HAPs combined, the RME facility is not subject to the provisions of 40 CFR Part 63.
- D. ARM 17.8, Subchapter 4, Stack Height and Dispersion Techniques, including, but not limited to:
1. ARM 17.8.401 Definitions. This rule includes a list of definitions used in this chapter, unless indicated otherwise in a specific subchapter.
 2. ARM 17.8.402 Requirements. RME must demonstrate compliance with the ambient air quality standards with a stack height that does not exceed Good Engineering Practices (GEP). RME demonstrated, through the air quality modeling and downwash review, that the new stack heights are consistent with GEP.
- E. ARM 17.8, Subchapter 5, Air Quality Permit Application, Operation and Open Burning Fees, including, but not limited to:
1. ARM 17.8.504 Air Quality Permit Application Fees. This rule requires that an applicant submit an air quality permit application fee concurrent with the submittal of an air quality permit application. A permit application is incomplete until the proper application fee is paid to the Department. RME submitted the appropriate permit application fee for the current permit action.
 2. ARM 17.8.505 Air Quality Operation Fees. An annual air quality operation fee must, as a condition of continued operation, be submitted to the Department by each source of air contaminants holding an air quality permit, excluding an open burning permit, issued by the Department. The air quality operation fee is based on the actual or estimated actual amount of air pollutants emitted during the previous calendar year.
- The annual assessment and collection of the air quality operation fee, as described above, shall take place on a calendar-year basis. The Department may insert into any final permit issued after the effective date of these rules such conditions as may be necessary to require the payment of an air quality operation fee on a calendar-year basis, including provisions which pro-rate the required fee amount.
- F. ARM 17.8, Subchapter 7, Permit, Construction and Operation of Air Contaminant Sources, including, but not limited to:
1. ARM 17.8.740 Definitions. This rule is a list of applicable definitions used in this chapter, unless indicated otherwise in a specific subchapter.

2. ARM 17.8.743 Montana Air Quality Permits--When Required. This rule requires a person to obtain an air quality permit or permit alteration to construct, alter or use any air contaminant sources that have the Potential to Emit (PTE) greater than 25 tons per year of any pollutant. RME has the PTE more than 25 tons per year of particulate matter (PM), particulate matter with an aerodynamic diameter of less than 10 microns (PM₁₀), oxides of nitrogen (NO_x), carbon monoxide (CO) sulfur dioxide (SO_x) and Volatile Organic Compounds (VOCs); therefore, a permit is required.
3. ARM 17.8.744 Montana Air Quality Permits--General Exclusions. This rule identifies the activities that are not subject to the Montana Air Quality Permit program.
4. ARM 17.8.745 Montana Air Quality Permits—Exclusion for De Minimis Changes. This rule identifies the de minimis changes at permitted facilities that do not require a permit under the Montana Air Quality Permit Program.
5. ARM 17.8.748 New or Modified Emitting Units--Permit Application Requirements. (1) This rule requires that a permit application be submitted prior to installation, alteration or use of a source. RME submitted the required permit application for the current permit action. (7) This rule requires that the applicant notify the public by means of legal publication in a newspaper of general circulation in the area affected by the application for a permit. RME submitted an affidavit of publication of public notice for the September 29, 2005, issue of the *Billings Gazette*, a newspaper of general circulation in the Town of Billings in Yellowstone County, as proof of compliance with the public notice requirements.
6. ARM 17.8.749 Conditions for Issuance or Denial of Permit. This rule requires that the permits issued by the Department must authorize the construction and operation of the facility or emitting unit subject to the conditions in the permit and the requirements of this subchapter. This rule also requires that the permit must contain any conditions necessary to assure compliance with the Federal Clean Air Act (FCAA), the Clean Air Act of Montana, and rules adopted under those acts.
7. ARM 17.8.752 Emission Control Requirements. This rule requires a source to install the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. The required BACT analysis is included in Section III of this permit analysis.
8. ARM 17.8.755 Inspection of Permit. This rule requires that air quality permits shall be made available for inspection by the Department at the location of the source.
9. ARM 17.8.756 Compliance with Other Requirements. This rule states that nothing in the permit shall be construed as relieving RME of the responsibility for complying with any applicable federal or Montana statute, rule, or standard, except as specifically provided in ARM 17.8.740, *et seq.*
10. ARM 17.8.759 Review of Permit Applications. This rule describes the Department's responsibilities for processing permit applications and making permit decisions on those permit applications that do not require the preparation of an environmental impact statement.
11. ARM 17.8.762 Duration of Permit. An air quality permit shall be valid until revoked or modified, as provided in this subchapter, except that a permit issued prior to construction of a new or altered source may contain a condition providing that the permit will expire unless construction is commenced within the time specified in the

permit, which in no event may be less than one year after the permit is issued.

12. ARM 17.8.763 Revocation of Permit. An air quality permit may be revoked upon written request of the permittee, or for violations of any requirement of the Clean Air Act of Montana, rules adopted under the Clean Air Act of Montana, the FCAA, rules adopted under the FCAA, or any applicable requirement contained in the Montana State Implementation Plan (SIP).
13. ARM 17.8.764 Administrative Amendment to Permit. An air quality permit may be amended for changes in any applicable rules and standards adopted by the Board of Environmental Review (Board) or changed conditions of operation at a source or stack that do not result in an increase of emissions as a result of those changed conditions. The owner or operator of a facility may not increase the facility's emissions beyond permit limits unless the increase meets the criteria in ARM 17.8.745 for a de minimis change not requiring a permit, or unless the owner or operator applies for and receives another permit in accordance with ARM 17.8.748, ARM 17.8.749, ARM 17.8.752, ARM 17.8.755, and ARM 17.8.756, and with all applicable requirements in ARM Title 17, Chapter 8, Subchapters 8, 9, and 10.
14. ARM 17.8.765 Transfer of Permit. This rule states that an air quality permit may be transferred from one person to another if written notice of Intent to Transfer, including the names of the transferor and the transferee, is sent to the Department.

G. ARM 17.8, Subchapter 8, Prevention of Significant Deterioration of Air Quality, including, but not limited to:

1. ARM 17.8.801 Definitions. This rule is a list of applicable definitions used in this subchapter.
2. ARM 17.8.818 Review of Major Stationary Sources and Major Modification--Source Applicability and Exemptions. The requirements contained in ARM 17.8.819 through ARM 17.8.827 shall apply to any major stationary source and any major modification with respect to each pollutant subject to regulation under the FCAA that it would emit, except as this subchapter would otherwise allow.

Because the RME facility is a chemical processing plant of more than 250 MMBtu/hr heat input, it is considered a "listed" source. As a listed source, the major source threshold under the Prevention of Significant Deterioration (PSD) regulations is lowered from 250 tons per year to 100 tons per year. The RME ethanol production facility is defined as a "major stationary source" because it is a listed source (chemical processing plant) with the PTE more than 100 tons per year of PM, PM₁₀, NO_x, SO₂, VOCs, and CO.

H. ARM 17.8, Subchapter 12 - Operating Permit Program Applicability, including, but not limited to:

1. ARM 17.8.1201 Definitions. (23) Major Source under Section 7412 of the FCAA is defined as any stationary source having:
 - a. PTE > 100 tons/year of any pollutant;
 - b. PTE > 10 tons/year of any one HAP, PTE > 25 tons/year of a combination of all HAPs, or lesser quantity as the Department may establish by rule; or

- c. PTE > 70 tons/year of PM₁₀ in a serious PM₁₀ nonattainment area.
- 2. ARM 17.8.1204 Air Quality Operating Permit Program Applicability. Title V of the FCAA Amendments of 1990 requires that all sources, as defined in ARM 17.8.1204(1), obtain a Title V Operating Permit. In reviewing and issuing Air Quality Permit #3402-00 for RME, the following conclusions were made:
 - a. The facility's PTE is greater than 100 tons/year for several criteria pollutants.
 - b. The facility's PTE is less than 10 tons/year of any one HAP and less than 25 tons/year of all HAPs.
 - c. This facility is not located in a serious PM₁₀ nonattainment area.
 - d. This facility is subject to several current NSPS standards (40 CFR 60, Subparts Db, Dc, Kb, and VV).
 - e. This facility is not subject to a current NESHAP standard.
 - f. This facility is not a Title IV affected source.
 - g. This facility is not an EPA designated Title V source.

Based on the above information, the RME facility is a major source for Title V and, thus, a Title V Operating Permit is required.

III. BACT Determination

A Best Available Control Technology (BACT) determination is required for each new or altered source. RME shall install on the emissions sources the maximum air pollution control capability that is technically practicable and economically feasible, except that BACT shall be utilized. A BACT analysis was submitted by RME in Montana Air Quality Permit Application #3402-00. The BACT analysis addresses some available methods of controlling VOC, CO, NO_x, SO₂, and PM/PM₁₀ emissions for the grain handling, coal handling, fermentation process, distillation process, DDGS Dryer, DDGS Cooler, coal boilers, natural gas boilers, the ethanol loadout process, cooling towers, fugitives, and the generator.

The Department reviewed the proposed control methods, previous BACT determinations (via the Reasonable Available Control Technology (RACT)/BACT/Lowest Achievable Emission Reduction (LAER) Clearinghouse, federal agency databases, and state agency decisions), and ongoing control proposals (via federal agencies and state agencies), prior to making the following BACT determination.

A. Pollutant Specific BACT Review

- 1. VOC Emission Control Technology - The Department evaluated several types of VOC control technologies including thermal oxidizers, flares, routing emissions for use as combustion air, refrigeration condensers, carbon adsorption, wet scrubbers, catalytic oxidizers, internal floating roof (storage tanks only), vapor balancing (storage tanks only), and vapor recovery. The following analysis explains and summarizes the available VOC control options/strategies for the proposed project. Individual BACT determinations are in a subsequent section.

a. Carbon Adsorption

Carbon adsorption is a control technology often used to remove organic compounds from gaseous or liquid streams. Carbon adsorption uses a contact vessel to pass the waste gas stream through an activated carbon bed. The organic compounds in the

waste gas stream are collected at the interface of the activated carbon by intermolecular forces creating a VOC-rich carbon. The VOC-rich carbon is then removed from the carbon bed and new or “clean”, activated carbon is added to the bed. The VOC-rich carbon is reclaimed (i.e. converted back to “clean” carbon) by separating the VOC’s from the carbon. This separation process is typically achieved by stripping the carbon in an oxygen-deficient environment usually using steam as the stripping media to vaporize the organic material without burning the carbon or the VOC’s.

b. Routing for use as Combustion Air

Dilute VOC streams with significant oxygen content (i.e. similar to oxygen concentration of air) can be routed for use as combustion air in a boiler. Since the air will go through a combustion zone, VOCs will be oxidized along with whatever fuel is being combusted in the boiler. This control, if feasible by the design and operation of the boiler, is presumed equivalent to thermal oxidation by a dedicated control device.

c. Thermal Oxidizers

Thermal oxidizers are refractory lined enclosures with one or more burners in which the waste gas stream is routed through a high temperature combustion zone where the waste gas stream is heated and the combustible materials are burned. Thermal oxidizers typically operate at 1200 to 2100 degrees Fahrenheit (°F), depending on the compounds in the waste gas stream being controlled. The residence time for a thermal oxidizer typically ranges from 0.5 to 2 seconds. With such high operating temperatures and long residence times, thermal oxidizers are capable of efficiently controlling VOC emissions from a variety of waste streams. There are two general types of thermal oxidation units: heat recovery and direct-flame. Heat recovery type thermal oxidizers recover the heat generated by the combustion of the VOC laden waste gas stream to assist in the thermal oxidizer operation. There are two types of heat-recovery thermal oxidizers: recuperative and regenerative. Direct-flame oxidizers heat the exhaust stream to destruction temperature and vent the hot gas. Direct-flame thermal oxidizers do not preheat the inlet gas stream but energy can be recovered from the thermal oxidizer by using the hot exhaust gas to generate steam or hot water for the facility.

d. Wet Scrubbers

Wet Scrubbers designed for VOC control are designed primarily for creating intimate contact to promote absorption of soluble compounds. Absorption scrubbers typically consist of a contact tower with high surface area material (mass transfer material) in the middle. A scrubbing liquid is sprayed down the tower covering the mass transfer material as waste gas is blown in the bottom of the tower, creating intimate contact between liquid and gas. The soluble gaseous compound(s) then dissolves in the scrubbing liquid. The scrubbing liquid is then removed from the bottom of the tower and treated. The two predominant types of absorption scrubbers are packed and plate towers. Packed towers are vertical vessels that are filled with a packing material such as raschig rings or “saddle” shaped pieces of material. This packing creates significant surface area for the liquid and gas to contact. Plate towers are vertical vessels with horizontal sieve plates in the middle. The scrubbing liquid is sent down the tower filling the plate and the gas passes through the plate holes generating contact with the scrubbing liquid.

e. Flares

Flares are used to oxidize combustible organic materials at high temperatures. There are two types of flares; elevated and ground flares. Elevated flares are simple flares in which the waste gas stream is sent up a stack (usually 10 to 100 meters in height) and burned at the tip of the stack. Elevated flares burn supplemental fuel at the tip of the flare stack using a pilot flame to create a high-temperature combustion zone for the waste gas to burn.

Waste streams controlled by elevated flares must have 200 to 300 British thermal units (Btu) of combustible constituents per cubic foot (CF) of waste gas. Except for the ethanol loadout exhaust stream, the VOC sources at RME contain relatively low concentrations of combustible material. As a result, fuel would need to be added to these waste gas streams prior to venting at elevated flares. This would require several million Btus per hour of natural gas to enrich each waste gas stream prior to venting at an elevated flare.

Ground flares are more complex than elevated flares. Ground flares consist of multiple burners in refractory-lined enclosures that allow for longer residence time and higher destruction efficiency. Ground flares are similar, in terms of level of control and enclosure design, to thermal oxidization units; however, ground flares do not maintain a constant combustion zone temperature. Therefore, ground flares require supplemental natural gas to “enrich” the waste gas stream just as elevated flares.

f. Refrigeration Condensers

Refrigeration condensers are used to separate materials from gaseous streams by cooling and, in some cases, pressurizing a gas stream to cause some of the constituents to condense to liquid form. Condensers are designed to separate constituents based on the difference in dew points of the compounds that are targeted for separation. For example, a stream of benzene and oxygen could be separated by cooling the stream until the benzene condenses because oxygen (dew point –183 degrees Celsius (°C)) has a much lower dew point than benzene (dew point 80 °C).

g. Routing for use as Combustion Air

Dilute VOC streams with significant oxygen content (i.e. similar to oxygen concentration of air) can be routed for use as combustion air in a boiler. Since the air will go through a combustion zone, VOCs will be oxidized along with whatever fuel is being combusted in the boiler. This control, if feasible by the design and operation of the boiler, is presumed equivalent to thermal oxidation by a dedicated control device.

2. PM/PM₁₀ Control Technologies

Control technologies evaluated for PM/PM₁₀ included baghouses, cyclones, wet scrubbers, electrostatic precipitators (ESP), paved roads, dust suppression (plant roads), and mist eliminators (cooling towers only).

- a. Baghouses – Baghouses, or fabric filters are typically used to control PM/PM₁₀ emissions from facilities located in densely populated areas. Baghouses remove dust from a gas stream by passing the stream through a porous fabric. Particles form a

cake on the fabric that will act as the filtration device. This porous cake is occasionally removed by a pulsed jet of compressed air or by reversed air flow through the fabric. In both cases, the particles are collected in a hopper. Baghouses are highly efficient for controlling filterable PM, but are not designed to remove condensable PM. Baghouses are subject to failure if they are not properly operated and maintained. Baghouse control efficiencies range from 97 to 99 percent or more in most applications.

- b. Cyclones – are used to collect large particulates using mechanical operations. Particles enter the cyclone suspended in a gas stream, which is forced into a vortex by the shape of the cyclone. The particles resist the change in direction of the gas and are moved radially outward to the outer wall of the cyclone. The gas stream continues to spiral in the conical tube downward. Particles are forced to the outer wall of the cyclone where they are caught in the laminar layer of air next to the wall and are carried downward by gravity to a hopper. Cyclone collectors can achieve acceptable performance in select situations, but are subject to failure if they are not properly operated and maintained. Cyclones are less efficient than standard fabric filter systems.
- c. ESP – ESP technology is applicable to a variety of particulate matter sources. Electrostatic precipitators (ESP) use electrical forces to move particles out of the gas stream and onto collector plates. Particles are given an electric charge by forcing them to pass through a region of gaseous ions. Once the particles have been collected on the plates, they must be removed without re-entraining them into the gas stream. Particles are either removed by knocking them loose from the plates and allowing the collected mass to slide into a hopper or by spraying water down the collector plates and draining contaminated water to a collection tank for treatment or shipment. ESP performance is influenced by particulate loading, particulate size distribution, particulate electrical resistivity, and precipitator voltage and current. ESPs show the highest control efficiencies with fine and coarse particles (less than 0.1 micrometer or greater than 10 micrometers).
- d. Paved Roads are an option of surface improvement for controlling emissions from unpaved roads. The control efficiencies achievable by paving can be estimated by comparing emission factors for unpaved and paved road conditions. Based on normal silt loading (0.4 grams per square meter) conditions paved roads generate 70 to 80% less PM/PM₁₀.
- e. Dust Suppression – Surface treatment is one of the other control options available. Dust suppression can be in the form of wet suppression or chemical stabilization. Wet suppression refers to the addition of water to the roads, which keeps the road surface wet. Chemical stabilization attempts to change the physical characteristics of the roadway surface. This typically achieved by binding particles together to create a hardened surface that resembles a paved road except that the surface is not uniformly flat. Dust suppression applied as required or at least two times per year can reduce PM/PM₁₀.
- f. Mist Eliminators (Cooling Towers Only) – Cooling towers provide direct contact between the cooling water and the air passing through the tower. Water droplets may become entrained in the air stream and “drift” out of the cooling tower. Mist eliminators are typically installed and designed to minimize the amount of “drift loss” associated with cooling towers. Mist eliminators are physical devices that remove water droplets from the air stream by inertial separation. Natural, induced, and forced draft cooling towers can be equipped with mist eliminators.

3. NO_x Control Technologies

For the purposed of NO_x control technology, the Department evaluated firing practices, flue gas recirculation, selective catalytic reduction, non-selective catalytic reduction (reciprocating engines only), injection timing retard (reciprocating only), overfire air (boiler only), and low NO_x burners.

- a. Firing Practices – Boiler design effects NO_x emissions from the combustion of coal. Fluidized bed boilers produce an even temperature profile reducing hot zones that lead to the formation of NO_x.
- b. Flue Gas Recirculation – In a flue gas recirculation (FGR) system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the re-circulated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. FGR reduces NO_x emissions by diluting the combustion gases to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism, and by lowering the oxygen concentration in the primary flame zone, thus reducing thermal NO_x formation.
- c. Selective Catalytic Reduction – SCR is a post combustion gas treatment technique that uses a catalyst to reduce NO_x and nitrogen dioxide (NO₂) to molecular nitrogen, water, and oxygen. Ammonia vaporized and injected into the flue gas upstream of the catalyst bed combines with NO_x at the catalyst surface to form an ammonium salt intermediate. The ammonium salt intermediate then decomposes to produce elemental nitrogen and water. The catalyst lowers the temperature required for the chemical reaction between NO_x and NH₃. Catalysts used for the NO_x reduction include base metals, precious metals, and zeolites. Commonly, the catalyst of choice for the reaction is a mixture of titanium and vanadium oxides. An attribute common to all catalysts is the narrow “window” of acceptable system temperatures. In this case, the temperature window is approximately 480 and 800 °F. At temperatures below 575 °F, the NO_x reduction reaction will not proceed, while operation at temperatures exceeding 800 °F will shorten catalyst life and can lead to the oxidation of NH₃ to either nitrogen oxides (thereby increasing NO_x emissions) or possibly generating explosive levels of ammonium nitrate in the exhaust gas stream. The stack temperature for the Boiler is approximately 300 °F making the use of SCR technically difficult. Other factors impacting the effectiveness of SCR include catalyst reactor design, operating temperature, type of fuel fired, sulfur content of the fuel, design of NH₃ injection system, and the potential for catalyst poisoning.
- d. Selective Non-Catalytic Reduction Selective non-catalytic reduction (SNCR) is a post-combustion technology that may be applied to combustion devices to reduce NO_x emissions. The SNCR systems inject ammonia or urea into combustion gases to reduce NO_x emissions to nitrogen and water vapor. The ammonia/urea injection must take place when the gas is between 1600° and 2100° F. Higher temperatures will cause the reagent to oxidize creating more NO_x and lower temperatures will result in significant reagent slip. The capital cost for SNCR controls are relatively low, however, it is challenging in practice to design and build a system that is reliable and effective. SNCR systems typically achieve 30 to 60% reduction in practice.
- e. Non-Selective Catalytic Reduction (Reciprocating Engines Only) Non-selective catalytic reduction (NSCR) also known as a three-way conversion system, simultaneously reduces NO_x, carbon monoxide (CO), and hydrocarbons (HC) by passing exhaust gas over a catalyst (usually a nobel metal such as platinum, rhodium, or palladium). NSCR is used on exhaust gases when HC and CO levels are high. Thus, this control technology is only

feasible for reciprocating engines (properly designed turbines and boilers do not generate sufficient HC for NSCR). The excess HCs and CO are used as reducing reagents for converting NO_x to nitrogen and water. The catalyst also converts CO and hydrocarbons to CO₂ and water. NSCR has been achieved in practice for rich-burn reciprocating engines.

- f. Injection Timing Retard (Reciprocating Engines Only) - Injection timing retard (ITR) is a common form of combustion modifications that can be used to control NO_x emissions from diesel fired engines. Retarding the timing of the diesel fuel injection into the cylinder causes the combustion process to occur when the combustion chamber volume is increasing, thus reducing temperature and pressure. The reduced temperature and pressure lower NO_x formation. The effectiveness of ITR is specific to each engine model. ITR increases PM/PM₁₀ emissions as well as the brake specific fuel consumption.
- g. Overfire Air (OFA) (boiler only) diverts a portion of the total combustion air from the burners and injects it through a separate air port above the top level of burners. OFA is the typical NO_x control technique used in new subbituminous-fired boilers. OFA can achieve NO_x reductions of 20 to 30 percent over uncontrolled levels. The staging of the combustion cycle from an initial fuel-rich combustion zone, to a cooler fuel-lean combustion zone reduces the production of thermal NO_x by lowering combustion temperature when nitrogen (N₂) is most available.
- h. Low NO_x Burners (LNB) reduce NO_x by accomplishing the combustion process in stages. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. Staging partially delays the combustion process, resulting in a cooler flame, which suppresses thermal NO_x formation. NO_x emission reductions of 40 to 85 percent have been observed with LNB.

4. CO Control Technologies

Oxidation Catalyst along with good combustion practices were the control technologies evaluated for CO.

CO is the result of incomplete combustion. Several design modifications have been made in recent decades to reduce the CO formation in combustion devices. However, the challenging task has been to decrease CO without increasing the formation of NO_x. Modern combustion devices such as boilers are designed to maximize the residence time or the combustion temperature throughout the combustion zone while keeping the flame temperature down.

Oxidation Catalyst – In addition to good burner design and good combustion practices CO can be reduced using an oxidation catalyst. The catalyst converts CO to CO₂ in the presence of oxygen. The catalyst is made of platinum or other precious metal. The catalyst typically operates between 350 and 1200 °F.

5. SO₂ Control Technologies

SO₂ control technologies evaluated include flue gas desulfurization (FGD), dry scrubbers, wet scrubbers, limestone injection (FBC Boiler Only) and coal cleaning.

The Department reviewed these methods, as well as previous BACT determinations for similar permitted sources. As described below, various control options were reviewed by the Department for the purpose of making the following pollutant-specific BACT

determinations.

a. Flue Gas Desulfurization (FGD)

Flue gas desulfurization (FGD) systems treat flue gases with wet, semi-dry, or dry desulfurization processes. FGD systems may discard all of the waste by product streams (throwaway type) or regenerate and reuse them (regenerable). Wet systems generally use alkali slurries as the SO_2 absorbent medium and can be designed to remove in excess of 90 percent of the incoming SO_2 . Lime/limestone scrubbers, sodium scrubbers, spray drying, and dual alkali scrubbing are among the proven FGD techniques.

b. Dry Scrubbers

Spray drying is a common dry scrubbing approach in which a solution or slurry of alkaline material is sprayed into a reaction vessel as a fine mist and mixes with the flue gas. The SO_2 reacts with the alkali solution or slurry to form liquid-phase salts. The slurry is dried by the latent heat of the flue gas to form sulfite and sulfate salts. The spray dryer solids are entrained in the flue gas and carried out of the dryer to a particulate control device such as an ESP or baghouse.

c. Wet Scrubbers

There are a variety of wet scrubber techniques to control SO_2 emissions. Absorption scrubbers come in variety of designs but operate on the same primary absorption principles. Absorption scrubbers typically consist of a contact tower with a high surface area material (mass transfer material) in the middle. A scrubbing liquid is sprayed down the tower covering the mass transfer material as waste gas is blown in the bottom of the tower, creating intimate contact between the liquid and gas. The soluble gaseous compound(s) then dissolve in the scrubbing liquid. In the case of SO_2 removal an alkaline reagent is dissolved in the liquid (water) and a chemical reaction consumes the SO_2 . The scrubbing liquid is then removed from the bottom of the tower and treated. Packed towers are vertical vessels that are filled with a packing material such as raschig rings or "saddle" shaped pieces of material. This packing creates significant surface area for the liquid and gas to contact. Plate towers are vertical vessels with horizontal sieve plates in the middle. The scrubbing liquid is sent down the tower filling the plate and the gas passes through the plate's holes generating contact with the scrubbing liquid. Packed towers are more efficient; however, plate towers are used when there is significant particulate matter in the waste gas stream because packed towers are susceptible to clogging when the waste gas stream contains significant PM. Because the SO_2 streams evaluated in this BACT analysis do not contain significant particulate matter (it is controlled by a fabric filter), packed bed towers are the most effective (for cost and control) wet scrubbers for reducing SO_2 emissions and will, therefore, be the only scrubber evaluated for SO_2 control.

d. Limestone Injection (FBC Boiler only)

Limestone may be injected into the furnace, typically in a fluid bed combustor (FBC), to react with sulfur dioxide and form calcium sulfate, an environmentally benign powder that is collected in the particulate controls. A FBC is composed of a bed of inert material that is suspended or "fluidized" by a stream of air. Subbituminous coal is injected into this bed and burned along with the coal particles where it reacts with the limestone. This is what differentiates limestone injection from any flue gas desulfurization control.

e. Coal Cleaning

Physical coal cleaning is the process of crushing coal into small particles and then employing some form of gravity separation that separates the particles by density. The pyrite-rich particles are denser than organic-rich particles and are removed by this principle. The sulfur content of coals fall into three categories, pyretic, organic, and sulfate sulfur. Physical coal cleaning only removes pyretic sulfur, and so the particular composition of the coal to be used is important in determining the feasibility of coal cleaning. The SO₂ control efficiencies achievable with coal cleaning are 10-40% depending on the composition and total sulfur content of the coal. Typically pyretic sulfur accounts for less than half of the total sulfur and the coal cleaning process removes less than half of the pyrite. The costs of a coal cleaning process are seldom justified by sulfur removal alone, and it is typically a method for coal suppliers to add value to their product, not an on-site control technology.

A disadvantage is that a 2-15% energy loss is incurred as organic matter is separated along with the pyrite, and further efficiency losses are incurred if water is used to separate the coal particles as this reduces boiler thermal efficiency.

B. Source Specific BACT Analysis

1. Grain Handling, Hammermilling, and DDGS Handling

PM BACT Summary - The pollutant of concern in the grain handling, hammermilling, and DDGS processes is PM/PM₁₀. ESPs are eliminated as a feasible option for controlling grain handling, hammermilling, and DDGS handling particulate emissions because it is a safety hazard. Particulate dust has the potential to explode if exposed to an ignition source such as a spark between the charged ESP plates. The remaining control technologies were ranked by effectiveness

Baghouses and Cyclones were evaluated as feasible add-on controls for the grain handling exhaust. Fabric filters are the most effective control technology available for controlling the grain handling, hammermilling, and DDGS handling PM/PM₁₀ emissions.

The Department determined BACT for the grain handling equipment, hammermilling process and DDGS handling equipment is 99% control of PM/PM₁₀ emissions or a maximum of 0.004 grains of PM/PM₁₀ per dry standard cubic foot of exhaust (gr/dscf). RME will be required to install and operate a baghouse on each of the three processes.

2. Coal Handling

PM BACT Summary - Coal will be received by truck and transferred to a coal silo bin at the boiler. Emissions are generated at the dropping of the coal into the receiving pit and at the silo bin prior to being fed to the boiler. The emissions are fine particles of unburned coal. The potential explosiveness of the particles is not severe; however, the potential for explosion if a spark is generated in the ESP does exist. For this reason, ESP control is considered technologically infeasible for the coal handling operations.

The add-on control technology evaluated for the coal handling process are baghouses, mist sprayers and cyclones. RME proposed to use a mist sprayer to wet the coal and control the dust as the coal is being received via truck. RME also proposed to install and operate a baghouse on the coal handling operations. The Department determined the installation and operation of mist spraying during receiving and a baghouse prior to being

fed to the boiler constitutes BACT for the coal handling operations. The baghouse shall achieve a control efficiency of 95% limiting PM/PM₁₀ emissions to less than 0.01 gr/dscf.

3. Fermentation

VOC BACT Summary - Since carbon adsorption typically requires a VOC concentration of at least 200 to 1000 ppmv and average VOC molecular weights of at least 50 to 60 atomic units, and the fermentation system does not meet these requirements, carbon adsorption is technologically infeasible for controlling the VOC emissions from the fermentation system.

Routing gas from the fermentation tanks for use as combustion air would decrease boiler efficiency, causing increased fuel consumption and SO₂, NO_x, and CO emissions from the boiler. Therefore, the negative energy and environmental affects of routing the fermentation emissions to the boiler is not considered a technologically feasible option.

Other control technologies considered include wet scrubbing, catalytic oxidation, thermal oxidation, flaring, and refrigeration condenser. Based on the fundamental properties behind each control, wet scrubbing is considered the top option for controlling VOC emissions from the fermentation system. The primary VOC controlled from fermentation would be ethanol, the product the plant would be producing; therefore, recovery is preferable to destruction. Wet scrubbing is the pollution control choice for dry mill ethanol plants for fermentation units because it is the only technology that re-directs ethanol back to the process. This design rationale is less wasteful, and is better environmentally than a destruction technology.

Wet scrubbing is the top technologically feasible add-on control for the fermentation VOC emissions. The Department determined that the wet scrubber is the most energy, cost, and control efficient technology, which constitutes BACT for VOC emissions on the fermentation process. Wet scrubbing will achieve 95% control of VOC emissions or if the inlet concentration is less than 200 ppm of VOC, then 20 ppm or lower of VOC.

4. Distillation

VOC BACT Summary - As with the fermentation process, carbon absorption typically requires a VOC concentration of at least 200 to 1000 ppmv and average VOC molecular weights of at least 50 to 60 atomic units. Because of the design of the project, carbon adsorption is, therefore, technologically infeasible for controlling the VOC emissions from the distillation system.

Wet scrubbing is considered the top technology for controlling VOC emissions from the distillation system as well as the fermentation process. The Department determined a wet scrubber constitutes BACT for the distillation systems, achieving 95% control for VOC emissions, or if the inlet concentration is less than 200 ppm of VOC, then 20 ppm or lower of VOC. This determination is consistent with similar and recently permitted facilities.

5. DDGS Dryers

PM BACT Summary - Baghouses were eliminated as technologically feasible because the DDGS dryer will have a moisture content between 37 and 57 percent. The high moisture content could cause particulate caking and clogging of the fabric filters over time. Wet scrubbing is also ineffective due to the temperature of the dryer exhaust and the low PM loading of the DDGS dryer system exhaust.

The DDGS dryers have a built-in system of multiclones to remove the large particulates; therefore, the PM/PM₁₀ emissions from the DDGS dryer system will consist primarily of PM less than 10 micrometers in diameter. The exhaust gas from the DDGS dryers will be over 200° F and therefore the condensable particulate will still be in gaseous form. As such, an ESP will be ineffective at controlling the condensable PM emissions from this and is therefore, not a technologically feasible control for the DDGS dryers.

RME proposed to route the air stream from the DDGS Dryers to the Fluid Bed Boiler for use as combustion air. This serves as a VOC control as well as a PM control. The particulate emissions will either be destroyed in the combustion zone of the boiler, or will be controlled in the pollution control equipment installed on the boiler.

The Department determined BACT for the DDGS Dryer's particulate matter emissions is routing the air stream to the Fluid Bed Boiler for use as combustion air. The emission limitation for the boiler will include the DDGS dryer emissions.

VOC BACT Summary – Control technology evaluated for VOC emissions from the DDGS Dryers include flares, refrigeration condensers, carbon adsorption, catalytic oxidizer, routing emissions for use as combustion air, thermal oxidation, and wet scrubbers.

Flares require supplemental natural gas to enrich the waste gas stream if the VOC concentration is low. In order to increase the heat value of the DDGS dryers, several hundred MMBtu's of natural gas would need to be added to the exhaust prior to flaring. Thermal oxidation provides similar control but with more efficiency; therefore, flares are determined to be technologically infeasible for VOC emission control on the DDGS drying system.

The DDGS dryer system exhaust characteristics make controlling VOC emissions with a refrigeration condenser ineffective; therefore, condensers are ineffective and technologically infeasible for the DDGS dryer emissions.

Carbon adsorption is technologically infeasible for controlling the VOC emissions from the DDGS dryer system because the VOC concentration of the dryer system is too low.

Catalytic oxidation is unreliable for this stream and does not offer cost savings over thermal oxidation. Equipment vendors do not recommend the use of catalytic oxidizers for this type of waste gas stream; therefore, catalytic oxidation is not a technologically feasible option.

Thermal oxidation and routing the DDGS dryer steam to the boiler as combustion air are the top technologically feasible add-on VOC control technologies for the DDGS dryer system exhaust. The boiler combustion air option is ranked above thermal oxidation due to its environmental benefits. This control scheme is equivalent to a separate thermal oxidizer in terms of control efficiency, but avoids consumption of additional fuel, eliminates the need for expensive add-on control equipment, and allows for energy recovery from the combustion of the VOC's.

The Department determined BACT for VOC emissions from the DDGS dryer is routing the dryer emissions to the fluidized bed boiler for use as combustion air. This will control approximately 95% of VOC emissions from the DDGS dryer system or a

maximum outlet concentration of 10 ppm.

6. Boilers – PC/FBC

PM BACT Summary - For particulate matter control, wet scrubbers are technologically infeasible for this gas stream due to the large quantity of particulate that is to be controlled, and the quantity of wastewater that would be generated. Particulate is intentionally being emitted with the limestone injection SO₂ controls that can only be reasonably collected in a dry state. The quantity of PM prior to the baghouse would cause problems for most absorbers. The particulate emissions would control total nearly 20,000 tons per year at this control point.

According to RBLC, baghouses and ESP's are relatively indistinguishable in the level of control that they will provide. RME proposed to install a fabric filter baghouse for reliability, energy conservation, and cost savings. BACT for the pc-fired boiler and the fluidized bed combustor is determined to be a fabric filter baghouse. With this control, RME shall maintain PM/PM₁₀ emissions from the PC boiler to less than 0.015 lb/MMBtu, and PM/PM₁₀ emissions from the fluidized bed combustor to less than 0.026 lb/MMBtu as BACT limits.

VOC BACT Summary – Control technology evaluated for the coal boiler's VOC emissions include thermal oxidation, flares, refrigeration condensers, carbon adsorption, wet scrubbers, and catalytic oxidation.

Thermal oxidizers do not reduce boiler VOC emissions and would result in additional NO_x, CO, and PM emissions. The potential VOC emissions from the coal-fired boiler are very small; therefore, thermal oxidation is not a technologically feasible control option for the boiler. Flares burn fuel in a similar or less efficient method as boilers. Therefore, the concentration would not be reduced by an appreciable quantity using a flare. Refrigeration condensers are designed to separate constituents based on the difference in dew points of the compounds that are targeted for separation. The boiler exhaust characteristics make controlling VOC emissions with refrigeration condenser technology infeasible. Carbon adsorption would not be effective control technology for the boiler VOC emissions because the VOC concentration is too low and the volumetric flow rate is too high. Wet scrubbers are not effective at controlling VOC emissions from the boiler because of too many constituents in the gas stream that have little solubility in water. Catalytic oxidizers will not effectively control VOC emissions from the boiler because the VOC amounts to only trace quantities and catalytic oxidizers generate VOC emissions in similar concentrations to those of boilers. Therefore, good combustion practices is the only feasible control option for the coal boilers. The PC-fired boiler will be limited to 0.0034 lb/MMBtu of VOC emissions as a BACT limit.

NO_x BACT Summary – SCR and NSCR were evaluated as NO_x emissions controls for the coal boilers. Both of these control methods were deemed technically infeasible for RME's coal boilers. RME will use separate control systems on each of the facility's coal boilers for more efficient NO_x control. A combination of overfire air, and an ammonia injection (for selective non-catalytic reduction) will be used to reduce NO_x emissions from each unit. The fluid bed boiler will have a NO_x BACT limit of 0.1 lb/MMBtu and the PC-fired boiler will have a NO_x BACT limit of 0.15 lb/MMBtu.

CO BACT Summary – Oxidation catalysts were determined to be technically infeasible as an add-on control for the control of CO emissions from the coal boilers because additional fuel would be needed which would increase CO emissions as well as increasing other pollutant emissions. Therefore, good combustion practices have been selected as BACT and will be required to control CO emissions from the PC-fired boiler

to 0.14 lb/MMBtu and CO emissions from the fluidized bed combustor to 0.11 lb/MMBtu.

SO₂ BACT Summary – Control technologies evaluated for SO₂ emissions from the coal boilers include coal cleaning, flue gas desulfurization (FGD) wet scrubbing, FGD spray drying.

Coal cleaning has been determined to be a technically infeasible method of controlling SO₂ emissions from the coal boilers because energy may be lost from the coal, the pyritic sulfur content of the coal used (subbituminous) would limit coal cleaning efficiency, and the reduction would not be proportional to the reduction at the outlet of the boiler control system, coal cleaning is not effective for this type of application.

Both wet scrubbing FGD and spray drying FGD use a basic water solution to react with the SO₂ to form sulfates. Both FGD technologies are effective, but wet scrubbing has the highest SO₂ removal efficiency of any FGD technology. In addition, limestone can be injected into the boiler to combine with SO₂ creating calcium sulfate, which is a particulate easily removed in a following baghouse. Limestone injection can decrease the SO₂ emissions from the boiler by 75%. Using limestone injection and a baghouse in conjunction with an FGD system will allow for 90% to 95% reduction of SO₂ emissions from the coal boilers.

Although wet dryers are the top control technology for reducing SO₂ emissions from coal combustion devices, spray dryers are comparable in efficiency and are used more often on units of this size. Spray dryers have been used at recently permitted, similar sources.

Control Technology	Average Cost Effectiveness (\$/ton)	Incremental Cost Effectiveness (\$/ton)
Wet Scrubbing – FBC Boiler	\$3,080	\$26,805
Wet Scrubbing – PC Boiler	\$631	\$5,420
Spray Drying – FBC Boiler	\$1,506	---
Spray Drying – PC Boiler	\$309	---

RME proposed to combine the exhaust stream from each boiler upstream from the SO₂ add-on control device. However, an economic analysis of each stream was considered. As shown in the table, the incremental cost of a wet scrubber is excessive; therefore, RME proposed to install a spray dryer unit after the limestone injection SO₂ controls in the FBC boiler. The semi-dry scrubber would reduce SO₂ emissions as well as control hydrochloric and hydrofluoric acid gases.

Based on the information submitted, and recently permitted similar facilities, the Department determined that using limestone injection along with installation of a spray drying system and a baghouse constitutes BACT for the coal-fired boilers. The facility will be required to control SO₂ emissions in the fluidized bed combustor to 0.09 lb/MMBtu and control SO₂ emissions from the PC-fired boiler to 0.13 lb/MMBtu as BACT limits.

7. Boiler – Natural Gas

VOC BACT Summary - Control technology evaluated for the coal boilers VOC emissions include thermal oxidation, flares, refrigeration condensers, carbon adsorption, wet scrubbers, and catalytic oxidation.

Thermal oxidizers do not reduce boiler VOC emissions and would result in additional

NO_x, CO and PM emissions. The potential VOC emissions from the coal fired boiler are very small; therefore, thermal oxidation is not a technologically feasible control option for the boiler. Flares burn fuel in a similar or less efficient method as boilers. Therefore, the concentration would not be reduced by an appreciable quantity using a flare. Refrigeration condensers are designed to separate constituents based on the difference in dew points of the compounds that are targeted for separation. The boiler exhaust characteristics make controlling VOC emissions with refrigeration condenser technology infeasible. Carbon adsorption would not be effective control technology for the boiler VOC emissions because the VOC concentration is too low and the volumetric flow rate is too high. Wet scrubbers are not effective at controlling VOC emissions from the boiler because of too many constituents in the gas stream that have little solubility in water. Catalytic oxidizers will not effectively control VOC emissions from the boiler because the VOC amounts to only trace quantities and catalytic oxidizers generate VOC emissions in similar concentrations to those of boilers.

Good combustion practice is the only feasible control technology for VOC emissions from the natural gas boiler. The boiler will be limited to 0.0054 lb/MMBtu of VOC emissions for a BACT limit.

NO_x BACT Summary - SCR and NSCR were evaluated as NO_x emissions controls for the natural gas-fired boilers. Both of these control methods were deemed technically infeasible for RME's natural gas boilers. RME will use install and operate Low NO_x Burners to control NO_x emissions not to exceed the BACT limit of 0.05 lb/MMBtu.

CO BACT Summary - Oxidation catalysts were determined to be technically infeasible as an add-on control for the control of CO emissions from the natural gas fired boilers because additional fuel would be needed which would increase CO emissions as well as increasing other pollutant emissions. Therefore, good combustion practices will be required to control CO emissions from the natural gas boilers to 0.084 lb/MMBtu.

SO₂ BACT Summary – Natural gas is a low sulfur fuel; therefore, no add-on controls is a feasible option and the facility will maintain emissions at or below 0.0006 lb/MMBtu.

8. DDGS Cooling System

VOC BACT Summary – The control technology evaluated for the DDGS Cooler VOC emissions include flares, refrigeration condensers, carbon adsorption, wet scrubbers, thermal oxidation and routing emissions for use as combustion air.

The cooler exhaust flow rate is greater than 30,000 ACFM and the VOC concentration will be diluted to about 20 ppm. Therefore, a flare and refrigeration condensers are not effective at controlling VOC emissions from the cooling cyclone. Carbon adsorption is not typically used for this type of waste gas stream and is considered technologically infeasible for controlling VOC emissions from the cooling cyclone. Wet scrubbing is not recommended for this type of gas stream because cooling cyclone VOC emissions will be very dilute and the constituents vary in solubility. Other technologies such as thermal oxidation are capable of higher and more consistent control; therefore, wet scrubbing is a technologically infeasible option for controlling VOC emissions from the cooling cyclone.

Catalytic oxidation units are not as effective for controlling alcohols (i.e. methanol) and do not offer the ability to recover the heat necessary to oxidize the VOC emissions. In addition, catalytic oxidation is likely to have lower control efficiency while requiring

higher capital expenditure and higher operating costs than thermal oxidation. Thermal oxidation and routing to the boiler as combustion air are similar in control efficiency. However, the boiler combustion air option is ranked above thermal oxidation due to its environmental benefits. This control scheme is equivalent to a separate thermal oxidizer in terms of control efficiency, but avoids consumption of additional fuel, eliminates the need for expensive add-on control equipment, and allows for energy recovery from the combustion of the VOCs.

BACT for the DDGS cooling system is routing the cooler emissions to the fluidized bed boiler for use as combustion air. This will control 95% of VOC emissions from the DDGS cooler system or a maximum outlet concentration of 10 ppm.

9. Ethanol Loadout

VOC BACT Summary - Carbon adsorption, wet scrubbers, flares, thermal oxidation and refrigeration condensers were evaluated as VOC emission controls for the ethanol loadout process.

Carbon adsorption is effective when there is sufficient VOC concentration and adequate van der Waals interactions. Because the primary VOC being emitted is ethanol, the van der Waals interactions will be limited. Therefore, the effectiveness of carbon adsorption is limited. Carbon adsorption is ineffective at controlling the VOCs from the loadout and is technologically infeasible. Wet scrubbers are not typically used in operations that are not continuous such as the ethanol loadout process. Also, the organic compounds in the natural gasoline have limited solubility in water, potentially affecting the control efficiency of the scrubber. Therefore, wet scrubbers are not technologically feasible for controlling VOC emissions from the ethanol loadout process.

Thermal oxidation, flares, and vapor recover condensers have been used at similar sources to control VOC emissions. These units have been capable of reliably controlling at least 95% of the VOC emissions from the organic liquid loading system. A flare has the highest control efficiency and is ranked as the top control technology for the ethanol loadout. Thermal oxidizers and condensers have significant energy requirements with no benefit over flares. BACT for VOC emissions from the ethanol loadout operations is for RME to install and operate a flare achieving 98% control.

10. Generator

PM/PM₁₀ BACT Summary – Baghouses are effective for controlling filterable particulate matter. The particulate matter generated by the diesel generator will consist of filterable particulate matter, a significant portion of which will be submicron in size, or condensable, and therefore, non-filterable. The concentration PM/PM₁₀ is also very dilute. Therefore, baghouse control is ineffective for a gas stream of this type and is not technologically feasible. Cyclones have been ruled out by the same reasoning. ESP's require significant amounts of electricity, and therefore are also technologically infeasible.

The emergency generator will operate during periods of power failure only. Therefore, additional add-on control technologies that require energy inputs are not technologically and/or economically feasible. The Department determined that BACT for PM/PM₁₀ emissions from the emergency generator is using good combustion practices to maintain emissions at or below the emission rate of 0.0007 lb/hp-hr.

NO_x BACT Summary – SCR, SNCR, and NSCR were technologies analyzed for NO_x

emission controls on the emergency diesel generator. The emergency generator will operate during periods of power failure only and is limited to 500 hr/yr of operation. Therefore, additional add-on control technologies that require energy inputs are not technologically and/or economically feasible. RME shall use good combustion practices to maintain the diesel generator NO_x emissions at or below the emission rate of 0.013 lb/hp-hr.

11. Storage Tanks

VOC control technology evaluated for the storage tanks include vapor balancing, vapor recovery, and internal floating roofs. Vapor balancing systems are common for fixed roof tanks, but can not be used in conjunction with the internal floating roof storage tanks that RME has proposed to install. In addition, vapor recovery systems are considered infeasible for internal floating roof tanks. The storage tanks at RME will install and operate internal floating roofs to control VOC emissions.

12. Cooling Towers

RME will install cellular mist eliminators on all cooling towers that limits PM/PM₁₀ emissions to no more than 0.005% of circulating water flow.

13. Truck Traffic

Paved roads, chemical dust suppression, and watering were the measures evaluated for controlling PM/PM₁₀ caused by truck traffic at RME. The facility proposed to pave all plant roads and prohibit truck traffic between midnight and 4:00 a.m. BACT for the truck traffic is installation of paved plant roads to prevent PM/PM₁₀ emissions and limiting hours of traffic.

14. DGGs Storage Building Vent

PM/PM₁₀ BACT Summary – Uncontrolled emission rates for PM/PM₁₀ are only 0.46 tons per year. Add-on controls would not be economically feasible for controlling the particulate emissions from the DDGS storage building vent. Therefore, BACT for the DDGS storage building vent will be best management practices for handling DDGS within the storage building to minimize dust generation.

IV. Emissions Inventory -- Permit #3402-00

Source	Tons/Year					
	PM	PM ₁₀	NO _x	CO	SO ₂	VOC
Grain Handling Baghouse #1	2.27	2.27				
Grain Handling Baghouse #2	1.10	1.10				
Hammermill Baghouse #1	0.90	0.90				
Hammermill Baghouse #2	0.90	0.90				
DDGS Handling Baghouse	0.52	0.52				
Uncaptured Grain Handling	1.51	0.34				
DDGS Storage Building	0.46	0.11				
Uncaptured DDGS	0.90	0.87				
Coal Silo	5.63	5.63				
Limestone Silo (Coal Handling Baghouse)	0.38	0.38				
Fly Ash Silo	0.38	0.38				
Fermentation/CO ₂ Scrubber						26.28
DDGS Dryer DDGS Cooler Boiler – PC-Fired FBC	62.76	62.76	241.78	232.01	210.81	44.62
Natural Gas Boilers	1.12	1.50	8.44	8.32	0.07	0.92
Generator	1.41	1.41	26.15	11.06	0.65	1.42
Ethanol Loadout						7.56
Ethanol Loadout Flare			3.23	5.42		
Storage Tanks						17.62
Coal Handling Fugitives	0.48	0.48				
Limestone Handling Fugitives	0.34	0.34				
Fly Ash Loadout Fugitives	0.34	0.34				
Truck Traffic	6.67	1.30				
Cooling Towers	3.47	3.47				
Totals	91.54	86.89	279.60	256.81	211.53	98.42

Grain Receiving, Cleaning, and Hammermilling

Grain Handling Baghouse #1

Process Airflow Rate: 15100 acfm
Hours of operation: 8760 hr/yr

TSP Emissions:

Emission Factor: 0.004 gr/dscf
Calculations: $0.0000057 \text{ lb/ft}^3 * 15100 \text{ acfm} * 60 \text{ min/hr} = 0.52 \text{ lb/hr}$
 $0.52 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 2.27 \text{ ton/yr}$

PM-10 Emissions:

Emission Factor: 0.004 gr/dscf
Calculations: $0.0000057 \text{ lb/ft}^3 * 15100 \text{ acfm} * 60 \text{ min/hr} = 0.52 \text{ lb/hr}$
 $0.52 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 2.27 \text{ ton/yr}$

Grain Handling Baghouse #2

Process Airflow Rate: 7300 acfm
Hours of operation: 8760 hr/yr

TSP Emissions:

Emission Factor: 0.004 gr/dscf
Calculations: $0.0000057 \text{ lb/ft}^3 * 7300 \text{ acfm} * 60 \text{ min/hr} = 0.25 \text{ lb/hr}$
 $0.25 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 1.10 \text{ ton/yr}$

PM-10 Emissions:

Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 7300 \text{ acfm} * 60 \text{ min/hr} =$	0.25 lb/hr
	$0.25 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	1.10 ton/yr

Hammermill Baghouse #1

Process Airflow Rate:	6000 acfm	
Hours of operation:	8760 hr/yr	
TSP Emissions:		
Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 6000 \text{ acfm} * 60 \text{ min/hr} =$	0.21 lb/hr
	$0.21 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	0.90 ton/yr
PM-10 Emissions:		
Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 6000 \text{ acfm} * 60 \text{ min/hr} =$	0.21 lb/hr
	$0.21 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	0.90 ton/yr

Hammermill Baghouse #2

Process Airflow Rate:	6000 acfm	
Hours of operation:	8760 hr/yr	
TSP Emissions:		
Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 6000 \text{ acfm} * 60 \text{ min/hr} =$	0.21 lb/hr
	$0.21 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	0.90 ton/yr
PM-10 Emissions:		
Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 6000 \text{ acfm} * 60 \text{ min/hr} =$	0.21 lb/hr
	$0.21 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	0.90 ton/yr

DDGS Handling Baghouse

Process Airflow Rate:	3500 acfm	
Hours of operation:	8760 hr/yr	
TSP Emissions:		
Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 3500 \text{ acfm} * 60 \text{ min/hr} =$	0.12 lb/hr
	$0.012 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	0.52 ton/yr
PM-10 Emissions:		
Emission Factor:	0.004 gr/dscf	
Calculations:	$0.00000057 \text{ lb/ft}^3 * 3500 \text{ acfm} * 60 \text{ min/hr} =$	0.12 lb/hr
	$0.12 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} =$	0.52 ton/yr

Uncaptured Grain Handling

Throughput:	98.4 ton/hr	
Hours of operation:	8760 hr/yr	
TSP Emissions:		
Emission Factor:	0.035 lb/ton	
Calculations:	$0.035 \text{ lb/ton} * 98.4 \text{ ton/hr} = 3.44 \text{ lb/hr}$	
	$3.44 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} * 0.10 = 1.51 \text{ ton/yr}$	
PM-10 Emissions:		
Emission Factor:	0.0078 lb/ton	

Calculations: $0.0078 \text{ lb/ton} * 98.4 \text{ ton/hr} = 0.77 \text{ lb/hr}$
 $0.77 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} * 0.10 = 0.34 \text{ ton/yr}$

DDGS Storage Building

Throughput: 32.06 ton/hr
Hours of operation: 8760 hr/yr

TSP Emissions:
Emission Factor: 0.0033 lb/ton
Calculations: $0.0033 \text{ lb/ton} * 32.06 \text{ ton/hr} = 0.11 \text{ lb/hr}$
 $0.11 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.46 \text{ ton/yr}$

PM-10 Emissions:
Emission Factor: 0.0008 ton/yr
Calculations: $0.0008 \text{ ton/yr} * 32.06 \text{ ton/hr} = 0.03 \text{ lb/hr}$
 $0.3 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.11 \text{ ton/yr}$

Uncaptured DDGS

Throughput: 32.06 ton/hr
Hours of operation: 8760 hr/yr

TSP Emissions:
Emission Factor: 0.0643 lb/ton
Calculations: $0.0643 \text{ lb/ton} * 32.06 \text{ ton/hr} = 2.06 \text{ lb/hr}$
 $2.06 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} * 0.10 = 0.90 \text{ ton/yr}$

PM-10 Emissions:
Emission Factor: 0.0618 lb/ton
Calculations: $0.0618 \text{ lb/ton} * 32.06 \text{ ton/hr} = 1.98 \text{ lb/hr}$
 $1.98 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} * 0.10 = 0.87 \text{ ton/yr}$

Coal Handling Emissions

Coal Silo

Throughput: 15,000 dscf/min
Hours of operation: 8760 hr/yr

TSP Emissions:
Emission Factor: 0.01 gr/dscf
Calculations: $0.01 \text{ gr/dscf} * 15,000 \text{ dscf/min} * 1 \text{ lb/7000 gr} * 60 \text{ min/hr} = 1.29 \text{ lb/hr}$
 $1.29 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 5.63 \text{ ton/yr}$

PM-10 Emissions:
Emission Factor: 0.01 gr/dscf
Calculations: $0.01 \text{ gr/dscf} * 15,000 \text{ dscf/min} * 1 \text{ lb/7000 gr} * 60 \text{ min/hr} = 1.29 \text{ lb/hr}$
 $1.29 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 5.63 \text{ ton/yr}$

Limestone Silo

Throughput: 1,000 dscf/min
Hours of operation: 8760 hr/yr

TSP Emissions:
Emission Factor: 0.01 gr/dscf
Calculations: $0.01 \text{ gr/dscf} * 1,000 \text{ dscf/min} * 1 \text{ lb/7000 gr} * 60 \text{ min/hr} = 0.09 \text{ lb/hr}$

$$0.09 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.38 \text{ ton/yr}$$

PM-10 Emissions:

Emission Factor: 0.01 gr/dscf

Calculations: $0.01 \text{ gr/dscf} * 1,000 \text{ dscf/min} * 1 \text{ lb/7000 gr} * 60\text{min/hr} = 0.09 \text{ lb/hr}$

$$0.09 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.38 \text{ ton/yr}$$

Fly Ash Silo

Throughput: 1,000 dscf/min

Hours of operation: 8760 hr/yr

TSP Emissions:

Emission Factor: 0.01 gr/dscf

Calculations: $0.01 \text{ gr/dscf} * 1,000 \text{ dscf/min} * 1 \text{ lb/7000 gr} * 60\text{min/hr} = 0.09 \text{ lb/hr}$

$$0.09 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.38 \text{ ton/yr}$$

PM-10 Emissions:

Emission Factor: 0.01 gr/dscf

Calculations: $0.01 \text{ gr/dscf} * 1,000 \text{ dscf/min} * 1 \text{ lb/7000 gr} * 60\text{min/hr} = 0.09 \text{ lb/hr}$

$$0.09 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.38 \text{ ton/yr}$$

Fermentation/CO₂ Scrubber

CO₂ Scrubber

VOC Emissions:

Hours of operation: 8760 hr/yr

Stream Flowrate: 200 lb/hr

Control Efficiency: 97%

Calculations: $200 \text{ lb/hr} * (1-0.97) = 6.0 \text{ lb/hr}$

$$6.0 \text{ lb/hr} * 8760 * .0005 \text{ ton/lb} = 26.28 \text{ ton/yr}$$

Fluidized Bed Combustor/PC-Fired Boiler

PC Boiler

Heat Input Capacity: 310.0 MMBtu/hr

Operating Hours: 8760 hr/yr

TSP Emissions Calculations

Emission Factor: 0.015 lb/MMBtu (Vendor estimate)

Calculations: $0.015 \text{ lbs/MMBtu} * 310.0 \text{ MMBtu/hr} = 4.65 \text{ lb/hr}$

$$4.65 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 20.37 \text{ ton/yr}$$

PM₁₀ Emission Calculations

Emission Factor: 0.015 lb/MMBtu (Vendor estimate)

Calculations: $0.015 \text{ lb/MMBtu} * 310.0 \text{ MMBtu/hr} = 4.65 \text{ lb/hr}$

$$4.65 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 20.37 \text{ ton/yr}$$

NO_x Emission Calculations

Emission Factor: 0.15 lb/MMBtu (Vendor Estimate/BACT Limit)

Calculations: $0.15 \text{ lb/MMBtu} * 310.0 \text{ MMBtu/hr} = 46.5 \text{ lb/hr}$
 $46.5 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 203.67 \text{ ton/yr}$

CO Emission Calculations

Emission Factor: 0.14 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.14 \text{ lb/MMBtu} * 310.0 \text{ MMBtu/hr} = 43.40$
 $43.40 * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 190.10 \text{ ton/yr}$

SO_x Emission Calculations

Emission Factor: 0.13 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.13 \text{ lb/MMBtu} * 310.0 \text{ MMBtu/hr} = 40.30$
 $40.30 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 176.51 \text{ ton/yr}$

VOC Emission Calculations

Emission Factor: 0.0034 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.0034 \text{ lb/MMBtu} * 310.0 \text{ MMBtu/hr} = 1.05 \text{ lb/hr}$
 $1.05 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 4.62 \text{ ton/yr}$

Fluidized Bed Combustor

Heat Input Capacity: 87.0 MMBtu/hr
Operating Hours: 8760 hr/yr

TSP Emissions Calculations

Emission Factor: 0.026 lb/MMBtu (Vendor estimate)
Calculations: $0.026 \text{ lbs/MMBtu} * 87.0 \text{ MMBtu/hr} = 2.26 \text{ lb/hr}$
 $2.26 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 9.91 \text{ ton/yr}$

PM₁₀ Emission Calculations

Emission Factor: 0.026 lb/MMBtu (Vendor estimate)
Calculations: $0.026 \text{ lb/MMBtu} * 87.0 \text{ MMBtu/hr} = 2.26 \text{ lb/hr}$
 $2.26 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 9.91 \text{ ton/yr}$

NO_x Emission Calculations

Emission Factor: 0.1 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.1 \text{ lb/MMBtu} * 87.0 \text{ MMBtu/hr} = 8.7 \text{ lb/hr}$
 $8.7 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 38.1 \text{ ton/yr}$

CO Emission Calculations

Emission Factor: 0.11 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.11 \text{ lb/MMBtu} * 87.0 \text{ MMBtu/hr} = 9.57 \text{ lb/hr}$
 $9.57 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 41.92 \text{ ton/yr}$

SO_x Emission Calculations

Emission Factor: 0.09 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.09 \text{ lb/MMBtu} * 87.0 \text{ MMBtu/hr} = 7.83$
 $7.83 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 34.3 \text{ ton/yr}$

VOC Emission Calculations

Emission Factor: 0.01 lb/MMBtu (Vendor Estimate/BACT Limit)
Calculations: $0.01 \text{ lb/MMBtu} * 87.0 \text{ MMBtu/hr} = 0.87 \text{ lb/hr}$

$$0.87 \text{ lb/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 3.81 \text{ ton/yr}$$

DDGS Cooler

The cooling/separating cyclones move the DDGS from the dryer to the DDGS storage. To estimate emissions from the grain movement, RME used stack test data from a similar facility, Glacial Lakes Ethanol (GLE). The emissions are scaled directly based on the ethanol production rate and include a 25% margin of error.

PM/PM₁₀ emission estimates

Ethanol Production: 80MMGal/yr

GLE Ethanol Production: 40 MMGal/yr

GLE PM emissions: 0.30 lb/hr

PM Emissions: $0.30 \text{ lb/hr} * 2 = 0.60 \text{ lb/hr}$

$$0.60 \text{ lb/hr} * 8760 \text{ hr/yr} * .0005 \text{ ton/lb} = 2.63 \text{ ton/yr}$$

VOC emission estimates

Ethanol Production: 80MMGal/yr

GLE Ethanol Production: 40 MMGal/yr

GLE VOC emissions: 1.11 lb/hr

VOC Emissions: $1.11 \text{ lb/hr} * 2 = 2.22 \text{ lb/hr}$

$$2.22 \text{ lb/hr} * 8760 \text{ hr/yr} * .0005 \text{ ton/lb} = 9.72 \text{ ton/yr}$$

DDGS Dryer

To estimate emissions from the DDGS dryer, RME used stack test data from a similar facility, Glacial Lakes Ethanol (GLE). The emissions are scaled directly based on the ethanol production rate and include a 25% margin of error.

PM/PM₁₀ emission estimates

Ethanol Production: 80 MMGal/yr

GLE Ethanol Production: 40 MMGal/yr

GLE PM emissions: 8.52 lb/hr

PM Emissions: $8.52 \text{ lb/hr} * 2 = 17.04 \text{ lb/hr}$

$$17.04 \text{ lb/hr} * 8760 \text{ hr/yr} * .0005 \text{ ton/lb} * (1-.60) = 29.86 \text{ ton/yr}$$

VOC emission estimates

Ethanol Production: 80 MMGal/yr

GLE Ethanol Production: 40 MMGal/yr

GLE VOC emissions: 75.45 lb/hr

VOC Emissions: $75.45 \text{ lb/hr} * 2 = 150.90 \text{ lb/hr}$

$$150.90 \text{ lb/hr} * 8760 \text{ hr/yr} * .0005 \text{ ton/lb} * (1-.96) = 26.44 \text{ ton/yr}$$

Natural Gas Boilers (2)

Hours of operation: 1500 hr/yr

Maximum Heat Input: 75.0 MMBtu/hr (HHV)

Natural Gas Heating Value: 1,020 Btu/scf (HHV)

Fuel Consumption: $75.0 \text{ MMBtu/hr} / 1,020 \text{ Btu/scf} = 0.074 \text{ MMscf/hr}$

TSP Emissions:

Emission Factor: 0.01 lb/MMBtu (Vendor estimate)

Calculations: $0.01 \text{ lb/MMBtu} * 75 \text{ MMBtu/hr} = 0.75 \text{ lb/hr}$

$$0.75 \text{ lb/hr} * 1500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.56 \text{ ton/yr}$$

PM-10 Emissions:
Emission Factor: 0.01 lb/MMBtu (Vendor estimate)
Calculations: $0.01 \text{ lb/MMBtu} * 75 \text{ MMBtu/hr} = 0.75 \text{ lb/hr}$
 $0.75 \text{ lb/hr} * 1500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.75 \text{ ton/yr}$

NOx Emissions:
Emission Factor: 0.075 lb/MMBtu (Vendor estimate after control)
Calculations: $0.075 \text{ lb/MMBtu} * 75 \text{ MMBtu/hr} = 5.62 \text{ lb/hr}$
 $5.62 \text{ lb/hr} * 1500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 4.22 \text{ ton/yr}$

VOC Emissions:
Emission Factor: 0.0082 lb/MMBtu (Vendor estimate)
Calculations: $0.0082 \text{ lb/MMBtu} * 75 \text{ MMBtu/hr} = 0.62 \text{ lb/hr}$
 $0.62 \text{ lb/hr} * 1500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.46 \text{ ton/yr}$

CO Emissions:
Emission Factor: 0.074 lb/MMBtu (Vendor estimate)
Calculations: $0.074 \text{ lb/MMBtu} * 75 \text{ MMBtu/hr} = 5.55 \text{ lb/hr}$
 $5.55 \text{ lb/hr} * 1500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 4.16 \text{ ton/yr}$

SOx Emissions:
Emission Factor: 0.6 lb/MMft³ (AP-42, Table 1.4-2, p.1.4-5, 7/93)
Calculations: $0.6 \text{ lb/MMft}^3 * 0.074 \text{ MMscf/hr} = 0.04 \text{ lb/hr}$
 $0.04 \text{ lb/hr} * 1500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.03 \text{ ton/yr}$

Emergency Generator

Generator Size: 8,046 hp
Operating Hours: 500 hr/yr

TSP Emissions Calculations

Emission Factor: 0.0007 lb/hp-hr (AP-42 5th addition, Section 3.4 “large Stationary Diesel and Stationary Dual-fuel Engines, 10/96)
Calculations: $8,046 \text{ hp} * 0.0007 \text{ lb/hp-hr} * 500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 1.41 \text{ ton/yr}$

PM₁₀ Emission Calculations

Emission Factor: 0.0007 lb/hp-hr (AP-42 5th addition, Section 3.4 “large Stationary Diesel and Stationary Dual-fuel Engines, 10/96)
Calculations: $8,046 \text{ hp} * 0.0007 \text{ lb/hp-hr} * 500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 1.41 \text{ ton/yr}$

NO_x Emission Calculations

Emission Factor: 0.0130 lb/hp-hr (AP-42 5th addition, Section 3.4 “large Stationary Diesel and Stationary Dual-fuel Engines, 10/96)
Calculations: $8,046 \text{ hp} * 0.0130 \text{ lb/hp-hr} * 500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 26.15 \text{ ton/yr}$

SO_x Emission Calculations

Emission Factor: 0.0003 lb/hp-hr (AP-42 5th addition, Section 3.4 “large Stationary Diesel and Stationary Dual-fuel Engines, 10/96)
Calculations: $8,046 \text{ hp} * 0.0003 \text{ lb/hp-hr} * 500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 0.60 \text{ ton/yr}$

CO Emission Calculations

Emission Factor: 0.0055 lb/hp-hr (AP-42 5th addition, Section 3.4 “large Stationary Diesel and Stationary Dual-fuel Engines, 10/96)
Calculations: $8,046 \text{ hp} * 0.0055 \text{ lb/hp-hr} * 500 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 11.06 \text{ ton/yr}$

Ethanol Loadout (Railcar)

Maximum Throughput: 84,000 gal/yr (Based on 8760 hours of operation per year)

Control Efficiency: 98% (Flare based on BACT)

VOC Emissions:

Max. Total Loss: 377.83 ton/yr (Based on 8760 hours of operation per year)

After Control: $377.83 \text{ ton/yr} * (1-0.98) = 7.56 \text{ ton/yr}$

Ethanol Loadout Flare

Maximum Throughput: 84,000 gal/yr

Capture: 98%

NO_x Emissions

Emission Factor: 0.077 lb/1000 gal loaded (RME permit application Appendix E)

Calculations: $0.077 \text{ lb/1000 gal} * 84,000 \text{ gal/yr} = 6.47 \text{ lb/yr}$
 $6.47 \text{ lb/yr} * .0005 \text{ ton/lb} = 0.0032 \text{ ton/yr}$

CO Emissions

Emission Factor: 0.129 lb/1000 gal loaded (RME permit application Appendix E)

Calculations: $0.129 \text{ lb/1000 gal} * 84,000 \text{ gal/yr} = 6.47 \text{ lb/yr}$
 $6.47 \text{ lb/yr} * .0005 \text{ ton/lb} = 0.0054 \text{ ton/yr}$

SO₂ is negligible based on minimal H₂S levels

PM/PM₁₀ is negligible based on smokeless design

Vehicle Traffic

Miles/Round Trip (miles/hr): 0.254 VMT/hr

PM Emission Calculations

Emission Factor: 6 lb/vehicle mile traveled (VMT) (Department Guidance Statement)

Calculations: $6 \text{ lb/VMT} * 0.254 \text{ VMT/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 6.67 \text{ ton/yr}$

PM₁₀ Emission Calculations

Emission Factor: 1.17 lb/VMT

Calculations: $1.17 \text{ lb/VMT} * 0.254 \text{ VMT/hr} * 8760 \text{ hr/yr} * 0.0005 \text{ ton/lb} = 1.30 \text{ ton/yr}$

V. Existing Air Quality and Impacts

Existing Air Quality

The plant site is located in the Southwest ¼ of Section 12, Township 1 South, Range 33 East, in Big Horn County, Montana. The air quality of this area is classified as either “Better than National Standards” or unclassifiable/attainment of the Montana and National Ambient Air Quality Standards (MAAQS and NAAQS) for criteria pollutants.

Air Quality Impacts

The air quality classification for the RME project area is “Unclassifiable or Better than National Standards” (40 CFR 81.327) for the National Ambient Air Quality Standards (NAAQS) for all criteria pollutants. The closest nonattainment area is a CO nonattainment area located in Billings, approximately 45 miles (72.4 kilometers (km)) west of the site. The closest Class I area is the non-

mandatory Northern Cheyenne Indian Reservation (NCIR), located 46 km east of the site. Impacts have also been evaluated at three other Class I areas located approximately 200 km from the site: Yellowstone National Park (YNP), North Absaroka Wilderness Area (NOAB) and UL Bend National Wildlife Refuge (UL Bend). Natural Resource Group, Inc. (NRG) submitted modeling on behalf of RME. The Department has worked with RME and NRG to establish a complete dispersion modeling analysis for demonstration of compliance with applicable increments and standards.

MODELING PARAMETERS

Emissions of NO_x, SO₂, CO, PM₁₀ and Pb were modeled to demonstrate compliance with the Montana and National Ambient Air Quality Standards (MAAQS and NAAQS) and the PSD increments. The modeling was performed in accordance the methodology outlined in the New Source Review Workshop Manual, EPA, October 1990, Draft and Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), April 15, 2003.

Prior to modeling the RME facility, NRG contacted the Department for modeling guidance and submitted an air quality modeling protocol. The protocol is included in Appendix G of the air quality permit application. Modeled source input parameters for RME sources are available upon request from the Department. The modeling included point sources, area sources and volume sources and the source parameters are consistent with accepted practice.

EPA's Industrial Source Complex (ISC3) model was used along with EPA's BPIP - PRIME downwash algorithm. The Department requested that RME's PM₁₀ model include all of the emission points at the adjoining Rocky Mountain Power (RMP) site, including fugitive dust sources as well as the main boiler stack. BPIP-PRIME downwash algorithm was used for the RMP point sources as well as the RME point sources for the Class II analysis. The Department ran the ISC-PRIME modeling files obtained from NRG to verify the modeling results.

RME's modeling used seven years of surface meteorological data (1984, 1986-1991) collected at the Billings International Airport National Weather Service (NWS) station. One year of meteorological data collected during 2002 and 2003 at RMP site was also used (data set "Hardin 2002"). Surface met data was processed with corresponding upper air data from the Great Falls NWS station. The processed met data files were provided to NRG by the Department.

According to the modeling protocol, RME's site will be fenced around the entire facility except for the railroad spur entrance/exit and the area west of the railroad spur. RME will use video surveillance to monitor the area west of the railroad spur. The ambient air boundary for the dispersion modeling analysis will follow the fenceline (including the cross-section of the railroad spur and the area west of the railroad spur).

Modeling receptors were established as described in the modeling protocol. The Class II modeling used a Cartesian grid and boundary receptor system with the following intervals and orientation:

- 50 meter (m) spacing along the facility fenceline;
- 100 m spacing from the proposed fenceline out to 1 kilometer (km);
- 250 m spacing from 1 km to 3 km;
- 500 meter spacing from 3 km to 10 km;
- 100 m spacing beyond 10 km;
- and a 10x10 (100 m spacing) receptor grid centered on any maximum modeled impact that occurs at a receptor located beyond the 100 m grid.

NRG also used an additional receptor set to determine the impacts of RME within RMP's ambient air quality boundary. The receptor grid was generated from digital elevation model (DEM) files

using the using 7.5-minute United States Geological Survey (USGS) topographical maps.

CLASS II PSD INCREMENT COMPLIANCE DEMONSTRATION

Although RME did not submit a significant impact analysis, the Department has extracted the significant impact information from the modeling submittal to develop a sense of the project impacts. RME's model results are compared to the applicable Class II significant impact levels (SIL's) in Table 1. RME's impacts exceed the SIL's for PM₁₀, NO_x and SO₂. The radius of impact (ROI) for each model is included in Table 1, and the largest radius of impact is 6.4 km for 24-hour SO₂. The area within the ROI is referred to as the significant impact area (SIA).

Table 1: RME Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. (µg/m ³)	Class II SIL ^a (µg/m ³)	Significant (y/n)	Radius of Impact (km)
PM ₁₀	24-hr	39.1	5 (1) ^b	Y	1.8
	Annual	7.7	1	Y	1.1
NO _x ^c	Annual	3.48	1	Y	1.0
CO	1-hr	130	2,000	N	-----
	8-hr	68.9	500	N	-----
SO ₂	3-hr	40.6	25	Y	3.4
	24-hr	13.5	5 (1) ^b	Y	6.4
	Annual	2.14	1	Y	3.6
O ₃	Net Increase of VOC: 98 tpy. Less than 100 tpy, source is exempt from O ₃ analysis.				

^a All concentrations are 1st-high for comparison to SIL's.

^b If a proposed source is located w/in 100 km of a Class I area, an impact of 1 µg/m³ on a 24-hour basis is significant.

^c Ambient Ratio Method (ARM) is not used for NO_x.

RME's modeling showed significant impacts for PM₁₀, NO_x and SO₂. Cumulative impact modeling was included to demonstrate compliance with the Class II PSD increments for these pollutants. The RMP power plant lies within the ROI for this facility, and is also a PSD-increment consuming source for SO₂, PM₁₀ and NO_x. Therefore, RMP's sources were included in the Class II PSD increment modeling. Source parameters for the RMP sources can be viewed in the RMP permitting file. Class II increment modeling results are compared to the applicable PSD increments in Table 2.

Table 2: Class II Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Class II Modeled Conc. (µg/m ³)	Class II Increment (µg/m ³)	% Class II Increment Consumed	Peak Impact Location
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PM ₁₀	24-hr	Hardin 2002	28.61	30	95%	(297886, 5069708)
	Annual	Hardin 2002	7.89	17	46%	(297635, 5069829)
SO ₂	3-hr	Hardin 2002	47.22	512	9.2%	(302873, 5069555)
	24-hr	Hardin 2002	23.89	91	26%	(300123, 5072055)
	Annual	Billings 1988	4.28	20	21%	(300123, 5072035)
NO ₂	Annual ^a	Billings 1988	3.11	25	12%	(300123, 5072055)

a – Annual NO₂ impacts are adjusted using the ambient ratio method. The NO_x impact is multiplied by the standard ARM adjustment factor of 0.75 to determine the NO₂ impacts.

PSD PRE-MONITORING REQUIREMENTS

Modeling results were used to determine whether RME needed to perform ambient air quality pre-monitoring as required under ARM 18.8.822. Table 3 compares the RME peak modeled impacts to the pre-monitoring exemption levels contained in ARM 18.8.818(7)(a). The facility is eligible for exemption from the pre-monitoring requirements for NO₂, CO and Pb. RME is not eligible for exemption from the pre-monitoring requirements for PM₁₀ and SO₂.

Table 3: RME Impact Compared to Pre-monitoring Exemption Levels

Pollutant	Avg. Period	Modeled Conc. (µg/m ³)	Exemption Level (µg/m ³) ^a	Eligible for Exemption (y/n)	Compliance with Pre-monitoring Requirement
PM ₁₀	24-hr	39.1	10	N	Use RMP pre-monitoring data.
NO ₂	Annual ^a	2.61	14	Y	
CO	8-hr	68.9	575	Y	
SO ₂	24-hr	13.5	13	N	Use RMP pre-monitoring data.
Pb	3-month	0.00005 ^c	0.1	Y	
O ₃	Net Increase of VOC: 98 tpy. Less than 100 tpy, source is exempt from O ₃ monitoring.				

^a All concentrations are 1st-high for comparison to the pre-monitoring exemption levels.

^b The ambient ratio method has been used to convert NO_x to NO₂.

^c Pb result based on 1-month averaging period

RMP has collected SO₂ and PM₁₀ pre-monitoring data at their site, located adjacent to the RME site. Due to the proximity of the RMP monitors, the Department has agreed to accept RMP's SO₂ and PM₁₀ monitoring data to satisfy the RME's pre-monitoring requirements. Table 4 lists the background monitoring data for the RMP site. These data represent background prior to operation of the RMP plant.

Table 4: RMP PM₁₀ and SO₂ Pre-monitoring Results, 2002-2003

Pollutant	Avg. Period	High Impact (ppm)	High Impact (µg/m ³)	HSH Impact (ppm)	HSH Impact (µg/m ³)	Ambient Standard ^a (µg/m ³)	% of Standard
PM ₁₀	24-hr	-----	82	-----	67	150	58

	Annual	-----	16	-----	-----	50	32
SO ₂	1-hr ^b	0.059	155	0.008 ^b	21.0	1300	1.6
	3-hr	0.026	68	0.006	15.7	1300	1.2
	24-hr	0.005	13.1	0.002	5.24	262	2.0
	Annual	0.001	2.62	-----	-----	52	5.0

^aMost restrictive MAAQS or NAAQS

^b1-hr MAAQS based on 19th high, monitor result is 10th high

The PM₁₀ concentrations measured on RMP's site are higher than Montana's default background values for areas with no other significant sources. Therefore, the NAAQS/MAAQS compliance demonstrations use RMP's PM₁₀ monitoring results for background data. The SO₂ monitored concentrations are slightly lower than the default background values so the SO₂ compliance demonstrations are based on the default background values.

NAAQS/MAAQS COMPLIANCE DEMONSTRATION

NAAQS/MAAQS modeling was conducted for PM₁₀, SO₂, and NO_x emissions from RMP. CO impacts from RME alone were below the modeling significance so no additional modeling was conducted for CO emissions. The ambient analysis included RMP as an existing source for the full impact analysis. No other major stationary sources exist within RME's SIA or within 50 kilometers beyond the SIA.

Modeling results are compared to the applicable MAAQS and NAAQS in Table 5. Modeled concentrations show the impacts from RME and RMP sources and include the background values. As shown in Table 5, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 5: NAAQS/MAAQS Compliance Demonstration

Pollutant	Avg. Period	Modeled Conc. ^a (µg/m ³)	Background Conc. (µg/m ³)	Ambient Conc. (µg/m ³)	NAAQS (µg/m ³)	% of NAAQS	MAAQS (µg/m ³)	% of MAAQS
PM ₁₀	24-hr	28.61	67	95.6	150	63.7	150	63.7
	Annual	7.89	16	23.9	50	47.8	50	47.8
NO ₂	1-hr	209 ^b	75	284	-----	-----	564	50.4
	Annual	3.11 ^c	6	9.11	100	9.11	94	9.69
SO ₂	1-hr	94.85	35	130	-----	-----	1,300	10.0
	3-hr	47.22	26	73.2	1,300	5.63	-----	-----
	24-hr	23.89	11	34.9	365	9.56	262	13.3
	Annual	4.82	3	7.82	80	9.78	52	15.0
Pb	Quarterly ^d	0.00043	Not. Avail.	0.00043	1.5	0.03		
	90-day ^d	0.00043	Not. Avail.	0.00043	-----	-----	1.5	0.03

^a Concentrations are high-second high values except annual averages and SO₂ 1-hr, which is high-6th-high.

^b The ozone limiting method has been applied to this result.

^c The ambient ratio method has been applied to this result.

^d The 1-month average impact is used for compliance demonstration.

The annual modeled NO_x impact was 4.15 µg/m³, which converts to 3.11 µg/m³ of NO₂ using the ambient ratio method. The maximum modeled 1-hour NO_x impact was 212 µg/m³ which converts to 209 µg/m³ of NO₂ using the ozone limiting method.

CLASS I INCREMENT ANALYSIS AT NCIR

PM₁₀, SO₂, and NO_x emissions were modeled using ISC-PRIME for the Class I (Northern Cheyenne Indian Reservation) Increment analyses. ISC-PRIME is the appropriate model for NCIR because it is located within 50 km of the proposed RME facility. Impacts at the Class I areas located farther from the site were modeled using CALPUFF.

The NCIR modeling results are shown in Table 6. All of the modeled impacts from RME were below Montana's proposed Class I SIL's. The Class I SIL's are all 4% of the associated Class I increment. The RME impacts are greatest at receptors on the western boundary of NCIR and drop with distance from the facility. The Department has determined that the RME project will not cause or contribute to a violation of a Class I increment based on the modeling results in Table 6. Therefore, cumulative modeling of increment-consuming sources is not necessary for this application. Because the modeled impacts are less than the Class I SIL's, the Department is confident that RME will not cause or contribute to a violation of the Class I PSD Increments.

Table 6: RME NCIR Class I Modeling Results (ISC-PRIME)

Pollutant	Avg. Period	Met Data Set	Class I Modeled Conc. (µg/m³)	Montana Class I SIL^a (µg/m³)	Is RME Significant ? (Y/N)	Peak Impact Location
PM ₁₀	24-hr	Hardin 2002	0.0814	0.3	N	(367925, 5059291)
	Annual	Hardin 2002	0.00378	0.2	N	(342474, 5044978)
SO ₂	3-hr	Hardin 2002	0.9861	1.0	N	(368820, 5059270)
	24-hr	Billings 1986	0.1176	0.2	N	(366931, 5059315)
	Annual	Hardin 2002	0.0097	0.1	N	(367031, 5059312)
NO _x	Annual ^a	Billings 1984	0.0402	0.1	N	(367031, 5059312)

^a Class I SIL's found in Table 5.1 of Montana's Modeling Guideline

VISIBILITY ANALYSIS AT NCIR (VISCREEN)

NCIR is located within 50 km of the RME site, making short-range visibility impact analysis appropriate.

RME estimated visibility impacts on NCIR following the methodology in EPA's Workbook for Estimating Visibility Impairment. RME submitted VISCREEN analysis to evaluate plume impacts on NCIR. All of the predicted plume impacts from RME's boiler were below the screening levels identified in the Level I VISCREEN analysis. No additional review of visibility impacts on the NCIR was needed.

CALPUFF MODELING FOR NOAB, AND UL BEND

RME submitted CALPUFF modeling to determine concentration, visibility and deposition impacts at the YNP, NOAB and UL Bend Class I areas. CALPUFF is the appropriate model for receptors at distances

greater than 50 km from the source. Guidelines for determining whether the Class I impacts were of concern came from the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000).

NRG submitted a refined CALPUFF modeling analysis on June 20, 2005. The Department reviewed the submittal and provided guidance for improving the analysis, including a request that NRG provide the impacts on each Class I area separately. NRG submitted a revised CALPUFF analysis on July 29, 2005. The revised analysis included RME-only concentration impacts for each mandatory Class I area. All the impacts were well below the Class I SIL's, so cumulative concentration impact analysis was not required. The Class I modeling report also included visibility analysis showing RME's peak impact at all three Class I areas. RME's impact was below the FLAG screening level of 5% change in background extinction range (ΔB_{ext}).

As part of the CALPUFF modeling review, the Department performed a CALPUFF screening analysis following the methodology developed by the Interagency Workgroup on Air Quality Modeling (IWAQM) (December 1998). The screening analysis used SAMSON data from the Billings NWS station, processed with upper air data from Great Falls. The results of the CALPUFF screening analysis confirmed that a refined, cumulative CALPUFF visibility analysis was not necessary.

The modeled concentration impacts from the CALPUFF screening analysis are available at the Department upon request. Montana's Class I SIL's are included for comparison to the results. The CALPUFF screening visibility results are also available at the Department upon request. The FLAG guideline states that the FLM's are unlikely to object to a source which does not cause any ΔB_{ext} greater than 5.0%. The deposition modeling results from the CALPUFF screening analysis show the peak predicted sulfur and nitrogen deposition rates are below the significance threshold in the FLAG guideline.

The IWAQM CALPUFF screening methodology provides a highly conservative estimate of the impacts of the RME facility. The Department has used this methodology to determine that the RME impacts will not be of concern in the YNP, NOAB and UL Bend Class I areas.

CONCLUSION

The modeling results for RME's proposed ethanol project have demonstrated compliance with the NAAQS/MAAQs and PSD increments. Modeling has also shown that the project is not expected to have an adverse impact on AQRV's in Class I areas.

VI. Taking or Damaging Implication Analysis

As required by 2-10-101 through 2-10-105, MCA, the Department conducted a private property taking and damaging assessment and determined there are no taking or damaging implications.

VII. Environmental Assessment

An environmental assessment, required by the Montana Environmental Policy Act, was performed for this permitting action. A copy is attached.

DEPARTMENT OF ENVIRONMENTAL QUALITY
Permitting and Compliance Division
Air Resources Management Bureau
P.O. Box 200901, Helena, Montana 59620
(406) 444-3490

FINAL ENVIRONMENTAL ASSESSMENT (EA)

Issued To: Rocky Mountain Ethanol, LLC
490 N. 31st St.
Billings, MT 59101

Air Quality Permit Number: #3402-00

Preliminary Determination Issued: October 3, 2005
Department Determination Issued: November 3, 2005
Permit Final: November 19, 2005

1. *Legal Description of Site:* RME ethanol production facility would be located near Hardin, Montana, in the SW¹/₄ of the NW¹/₄ of Section 12, Township 1 South, Range 33 East, Big Horn County, Montana.
2. *Description of Project:* RME proposes to construct and operate a fuel-grade ethanol production facility with the capacity to produce a maximum of 80-million gallons per year (MMGY) of undenatured ethanol. The facility would use a dry-mill production process to turn corn and barley into ethanol.
3. *Objectives of Project:* The objective of the project would be to allow RME construct and operate a fuel-grade ethanol production facility and sell their product to consumers. Additional by-products available for consumers would include carbon dioxide and Distillers Dried Grains with Solubles (DDGS) animal feed. The facility would not only provide approximately 38 industrial full-time jobs in the area, but would provide value-added support for the area corn and barley price.
4. *Alternatives Considered:* In addition to the proposed project, the Department also considered the "no action" alternative. The "no action" alternative would deny the issuance of the Montana Air Quality Permit (MAQP) to RME and would not allow the facility to be constructed and operated. Under the "no action" alternative, none of the impacts described in this EA would occur.
5. *A Listing of Mitigation, Stipulations, and Other Controls:* A list of enforceable conditions, including a BACT analysis, would be included in Permit #3402-00.
6. *Regulatory Effects on Private Property:* The Department considered alternatives to the conditions imposed in this permit as part of the permit development. The Department determined that the permit conditions would be reasonably necessary to ensure compliance with applicable requirements and demonstrate compliance with those requirements and would not unduly restrict private property rights.

7. The following table summarizes the potential physical and biological effects of the proposed project on the human environment. The "no action" alternative was discussed previously.

Potential Physical and Biological Effects							
		Major	Moderate	Minor	None	Unknown	Comments Included
A.	Terrestrial and Aquatic Life and Habitats			X			yes
B.	Water Quality, Quantity, and Distribution			X			yes
C.	Geology and Soil Quality, Stability, and Moisture			X			yes
D.	Vegetation Cover, Quantity, and Quality			X			yes
E.	Aesthetics			X			yes
F.	Air Quality			X			yes
G.	Unique Endangered, Fragile, or Limited Environmental Resource			X			yes
H.	Demands on Environmental Resource of Water, Air, and Energy			X			yes
I.	Historical and Archaeological Sites			X			yes
J.	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL PHYSICAL AND BIOLOGICAL EFFECTS: The following comments have been prepared by the Department.

A. Terrestrial and Aquatic Life and Habitats

The impacts from this project to terrestrial and aquatic life and habitats would be minor because of the relatively small portion of land that would be disturbed and the minor impact to the surrounding area from the air emissions (see Section VI of the permit analysis). The area around the facility would be fenced to limit access to the facility. The fencing would likely not restrict access from all animals that frequent the area, but it may discourage some animals from entering the facility property. Further, the facility would be located at a previous industrial site and other industrial sources, including the Rocky Mountain Power facility are located directly adjacent to the proposed RME property within a larger industrial park in the city limits of Hardin.

Aquatic life and habitats would realize a minor impact from the proposed facility because RME would be withdrawing water from the Bighorn River for its cooling tower. However, this water withdrawal would have little impact on the overall river flow and habitat, as discussed in Section 7.B of this EA. The proposed facility would recycle all waste generated by the ethanol plant and the resulting air emissions to any water body would be very minor.

The ambient air quality impact analysis of the air emissions from this facility indicates that the impacts from the RME emissions on land or surface water would be very minor and would consume only a small portion of the ambient air quality standards as discussed in Section VI of the permit analysis (see Section 7.F of this EA). The small amount of air

impact would correspond to an equally small amount of deposition.

B. Water Quality, Quantity, and Distribution

The proposed project would have potential storm water discharges during construction and operation. The proposed facility would occupy an existing industrial facility including impervious surfaces created by buildings, roads, and parking areas. Additional impervious surfaces would result from construction of additional buildings, equipment, tanks, roads, storage areas and a modification to the existing rail infrastructure. A storm water pollution prevention plan would be required for facility construction and operation. These plans would identify best management practices (BMP) for erosion control and storm water management with the goal of the plans being to minimize or eliminate wastes in storm water discharges. A storm water pond would be required to control run-off from the additional impervious surfaces added as a result of the project.

The proposed facility would not generate any process wastes. All wastes generated as a result of the ethanol process would be recycled for use within the process. The facility would generate non-contact wastewater from the proposed cooling tower, boiler, reverse osmosis system, and water softeners. These waste streams are planned to be discharged to the Big Horn River, and RME would be required to obtain applicable permits prior to any discharge. The industrial park, within which the proposed facility would be located, would eventually be connected to the City of Hardin's sanitary sewer system.

Wastewater discharge would include cooling tower operations at the facility requiring 97 gallons of water per minute (GPM) to operate properly. An additional 46 GPM would be required for the boiler blowdown, the reverse osmosis reject, and the water softener regeneration.

No surface water quality problems would result from the proposed project.

The proposed facility has acquired water rights to allocate 1300 GPM from the Bighorn River. An estimated 704 GPM would be required for non-contact cooling purposed, ethanol production, and the energy center.

A review of the National Wetland Inventory and Montana Wetland Survey has been conducted. According to these sources, no wetlands exist within the proposed project area. However, the construction of the water intake and discharge structures on the Bighorn River would have the potential to disturb riparian wetlands. These areas are not listed as the Department's Priority Wetlands or Heritage Wetlands. If necessary, a wetland delineation would be conducted to identify the location of regulated wetlands.

C. Geology and Soil Quality, Stability, and Moisture

The proposed project would have a minor effect on geology and soil quantity, stability, and moisture, because the facility would be constructed at an industrial property that has already been disturbed.

Based upon a review of the United States Department of Agriculture Natural Resources Conservation Service's Soil Survey Geographic Database (SSURGO), which provides soil information at the same level of detail as a county soil survey, the following soils are located within the project boundaries:

- Haverson silty clay;
- Kyle silty clay 0-2 percent slopes'
- Kyle silty clay, saline' and

- Heldt silty clay 0-2 percent slopes.

The majority of the site area has been previously disturbed due to prior industrial activities. The construction of the facility would result in the demolition of several existing buildings and foundations, as well as the addition of buildings and equipment associated with the ethanol production process. The total amount of new disturbance is estimated to be approximately 19 acres. This estimate is based on a preliminary site plan, and is subject to change based upon final grading plans.

D. Vegetation Cover, Quantity, and Quality

The proposed project would result in minor impacts on the vegetative cover, quantity, and quality in the immediate area because only a small amount of property would be disturbed and the resulting deposition from air emissions would be relatively small.

Construction and operation of the facility, as proposed, would not impact existing vegetative cover, quantity, or quality in the area because the proposed property is an abandoned sugar beet processing factory. As such, the plant species on site are grasses and shrubs associated with a disturbed and partially landscaped area. According to the Montana Natural Heritage Program's Element Occurrence Database, no known plant species of concern exist within the PLS section where the proposed project would be located. Weeds species that have the potential to be present in the project area are leafy spurge, spotted knapweed, Russian knapweed, and Dalmatian toadflax.

E. Aesthetics

The impacts to the aesthetics of the area from this project would be minor because the facility would be located within an industrial part in Hardin city limits. The proposed project would take place in an abandoned sugar beet processing plant and would not significantly change the existing aesthetic character of the site.

The nearest recreational opportunities would be provided by the Big Horn River. A fishing access site lies approximately two miles to the east of the proposed site on the Big Horn River. The proposed project is not anticipated to impact existing recreational opportunities in the area.

Further, noise levels would increase from the operation of the cooling towers, hammermills, and conveyance systems. The nearest noise sensitive area to the proposed site is a residence approximately 160 feet south of Sugar Factory Road.

The area would also receive increased vehicle use as a result of the proposed project; however, the Department does not believe that the amount of vehicle trips in the area would increase substantially over the existing traffic in the area. The facility would be located very near to an existing truck route and to other industrial facilities that currently use the route. Visible emissions from access roads (whether the county's responsibility or RME's responsibility) would be limited to 20% opacity.

Finally, operation of the proposed RME facility may result in increased industrial odors in the area. However, operation of the proposed facility would include measures to reduce the odor released from the plant.

F. Air Quality

The proposed RME facility would result in moderate air quality impacts because of the amount of air pollutants emitted and the good dispersion characteristics of the stack and the area. Emissions of NO_x, CO, PM, PM₁₀, VOC, SO₂, and HAP would result from the proposed project, with SO₂, NO_x, and CO above the 100 ton per year PSD major source threshold.

Air quality dispersion modeling (which factors in such parameters as wind speed, wind direction, atmospheric stability, stack temperature, stack emissions, etc.) was conducted for the facility by Natural Resources Group, Inc. (NRG). Emissions of NO_x, SO₂, CO, PM₁₀ and Pb were modeled to demonstrate compliance with the Montana and National Ambient Air Quality Standards (MAAQS and NAAQS) and the PSD increments. The modeling was performed in accordance the methodology outlined in the New Source Review Workshop Manual, EPA, October 1990, Draft and Appendix W of 40 CFR 51, Guideline on Air Quality Models (revised), April 15, 2003.

Prior to modeling the RME facility, NRG contacted the Department for modeling guidance and submitted an air quality modeling protocol. The protocol is included in Appendix G of the air quality permit application. The modeling included point sources, area sources and volume sources and the source parameters are consistent with accepted practice.

EPA's Industrial Source Complex (ISC3) model was used along with EPA's BPIP - PRIME downwash algorithm. The Department requested that RME's PM₁₀ model include all of the emission points at the adjoining Rocky Mountain Power (RMP) site, including fugitive dust sources as well as the main boiler stack. BPIP-PRIME downwash algorithm was used for the RMP point sources as well as the RME point sources for the Class II analysis. The Department ran the ISC-PRIME modeling files obtained from NRG to verify the modeling results.

RME's modeling used seven years of surface meteorological data (1984, 1986-1991) collected at the Billings International Airport National Weather Service (NWS) station. One year of meteorological data collected during 2002 and 2003 at the RMP site was also used (data set "Hardin 2002"). Surface met data was processed with corresponding upper air data from the Great Falls NWS station. The processed met data files were provided to NRG by the Department.

According to the modeling protocol, RME's site will be fenced around the entire facility except for the railroad spur entrance/exit and the area west of the railroad spur. RME will use video surveillance to monitor the area west of the railroad spur. The ambient air boundary for the dispersion modeling analysis will follow the fenceline (including the cross-section of the railroad spur and the area west of the railroad spur).

Modeling receptors were established as described in the modeling protocol. The Class II modeling used a Cartesian grid and boundary receptor system with the following intervals and orientation:

- 50 meter (m) spacing along the facility fenceline;
- 100 m spacing from the proposed fenceline out to 1 kilometer (km);
- 250 m spacing from 1 km to 3 km;
- 500 meter spacing from 3 km to 10 km;
- 100 m spacing beyond 10 km;

- and a 10x10 (100 m spacing) receptor grid centered on any maximum modeled impact that occurs at a receptor located beyond the 100 m grid.

NRG also used an additional receptor set to determine the impacts of RME within RMP's ambient air quality boundary. The receptor grid was generated from digital elevation model (DEM) files using the using 7.5-minute United States Geological Survey (USGS) topographical maps.

CLASS II PSD INCREMENT COMPLIANCE DEMONSTRATION

Although RME did not submit a significant impact analysis, the Department has extracted the significant impact information from the modeling submittal to develop a sense of the project impacts. RME's model results are compared to the applicable Class II significant impact levels (SIL's) in Table 1. RME's impacts exceed the SIL's for PM₁₀, NO_x and SO₂. The radius of impact (ROI) for each model is included in Table, and the largest radius of impact is 6.4 km for 24-hour SO₂. The area within the ROI is referred to as the significant impact area (SIA).

Table 1: RME Class II Significant Impact Modeling

Pollutant	Avg. Period	Modeled Conc. (µg/m ³)	Class II SIL ^a (µg/m ³)	Significant (y/n)	Radius of Impact (km)
PM ₁₀	24-hr	39.1	5 (1) ^b	Y	1.8
	Annual	7.7	1	Y	1.1
NO _x ^c	Annual	3.48	1	Y	1.0
CO	1-hr	130	2,000	N	-----
	8-hr	68.9	500	N	-----
SO ₂	3-hr	40.6	25	Y	3.4
	24-hr	13.5	5 (1) ^b	Y	6.4
	Annual	2.14	1	Y	3.6
O ₃	Net Increase of VOC: 98 tpy. Less than 100 tpy, source is exempt from O ₃ analysis.				

^a All concentrations are 1st-high for comparison to SIL's.

^b If a proposed source is located w/in 100 km of a Class I area, an impact of 1 µg/m³ on a 24-hour basis is significant.

^c Ambient Ratio Method (ARM) is not used for NO_x.

RME's modeling showed significant impacts for PM₁₀, NO_x and SO₂. Cumulative impact modeling was included to demonstrate compliance with the Class II PSD increments for these pollutants. The RMP power plant lies within the ROI for this facility, and is also a PSD-increment consuming source for SO₂, PM₁₀ and NO_x. Therefore, RMP's sources were included in the Class II PSD increment modeling. Source parameters for the RMP sources can be viewed in the RMP permitting file. Class II increment modeling results are compared to the applicable PSD increments in Table 2. Background concentrations are not PSD increment compliance demonstration.

Table 2: Class II Increment Compliance Demonstration

Pollutant	Avg. Period	Met Data Set	Class II Modeled Conc. ($\mu\text{g}/\text{m}^3$)	Class II Increment ($\mu\text{g}/\text{m}^3$)	% Class II Increment Consumed	Peak Impact Location
PM ₁₀	24-hr	Hardin 2002	28.61	30	95%	(297886, 5069708)
	Annual	Hardin 2002	7.89	17	46%	(297635, 5069829)
SO ₂	3-hr	Hardin 2002	47.22	512	9.2%	(302873, 5069555)
	24-hr	Hardin 2002	23.89	91	26%	(300123, 5072055)
	Annual	Billings 1988	4.28	20	21%	(300123, 5072035)
NO ₂	Annual ^a	Billings 1988	3.11	25	12%	(300123, 5072055)

a – Annual NO₂ impacts are adjusted using the ambient ratio method. The NO_x impact is multiplied by the standard ARM adjustment factor of 0.75 to determine the NO₂ impacts.

PSD PRE-MONITORING REQUIREMENTS

Modeling results were used to determine whether RME needed to perform ambient air quality pre-monitoring as required under ARM 18.8.822. Table 3 compares the RME peak modeled impacts to the pre-monitoring exemption levels contained in ARM 18.8.818(7)(a). The facility is eligible for exemption from the pre-monitoring requirements for NO₂, CO and Pb. RME is not eligible for exemption from the pre-monitoring requirements for PM₁₀ and SO₂.

Table 3: RME Impact Compared to Pre-monitoring Exemption Levels

Pollutant	Avg. Period	Modeled Conc. ($\mu\text{g}/\text{m}^3$)	Exemption Level ($\mu\text{g}/\text{m}^3$) ^a	Eligible for Exemption (y/n)	Compliance with Pre-monitoring Requirement
PM ₁₀	24-hr	39.1	10	N	Use RMP pre-monitoring data.
NO ₂	Annual ^a	2.61	14	Y	
CO	8-hr	68.9	575	Y	
SO ₂	24-hr	13.5	13	N	Use RMP pre-monitoring data.
Pb	3-month	0.00005 ^c	0.1	Y	
O ₃	Net Increase of VOC: 98 tpy. Less than 100 tpy, source is exempt from O ₃ monitoring.				

^a All concentrations are 1st-high for comparison to the pre-monitoring exemption levels.

^b The ambient ratio method has been used to convert NO_x to NO₂.

^c Pb result based on 1-month averaging period

RMP has collected SO₂ and PM₁₀ pre-monitoring data at their site, located adjacent to the RME site. Due to the proximity of the RMP monitors, the Department has agreed to accept RMP's SO₂ and PM₁₀ monitoring data to satisfy the RME's pre-monitoring requirements. Table 4 lists the background monitoring data for the RMP site. These data represent background prior to operation of the RMP plant.

Table 4: RMP PM₁₀ and SO₂ Pre-monitoring Results, 2002-2003

Pollutant	Avg. Period	High Impact (ppm)	High Impact (µg/m ³)	HSH Impact (ppm)	HSH Impact (µg/m ³)	Ambient Standard ^a (µg/m ³)	% of Standard
PM ₁₀	24-hr	-----	82	-----	67	150	58
	Annual	-----	16	-----	-----	50	32
SO ₂	1-hr ^b	0.059	155	0.008 ^b	21.0	1300	1.6
	3-hr	0.026	68	0.006	15.7	1300	1.2
	24-hr	0.005	13.1	0.002	5.24	262	2.0
	Annual	0.001	2.62	-----	-----	52	5.0

^aMost restrictive MAAQS or NAAQS

^b1-hr MAAQS based on 19th high, monitor result is 10th high

The PM₁₀ concentrations measured on RMP's site are higher than Montana's default background values for areas with no other significant sources. Therefore, the NAAQS/MAAQS compliance demonstrations use RMP's PM₁₀ monitoring results for background data. The SO₂ monitored concentrations are slightly lower than the default background values so the SO₂ compliance demonstrations are based on the default background values.

NAAQS/MAAQS COMPLIANCE DEMONSTRATION

NAAQS/MAAQS modeling was conducted for PM₁₀, SO₂, and NO_x emissions from RMP. CO impacts from RME alone were below the modeling significance so no additional modeling was conducted for CO emissions. The ambient analysis included RMP as an existing source for the full impact analysis. No other major stationary sources exist within RME's SIA or within 50 kilometers beyond the SIA.

Modeling results are compared to the applicable MAAQS and NAAQS in Table 5. Modeled concentrations show the impacts from RME and RMP sources and include the background values. As shown in Table 5, the modeled concentrations are below the applicable NAAQS/MAAQS.

Table 5: NAAQS/MAAQS Compliance Demonstration

Pollutant	Avg. Period	Modeled Conc. ^a (µg/m ³)	Background Conc. (µg/m ³)	Ambient Conc. (µg/m ³)	NAAQS (µg/m ³)	% of NAAQS	MAAQS (µg/m ³)	% of MAAQS
PM ₁₀	24-hr	28.61	67	95.6	150	63.7	150	63.7
	Annual	7.89	16	23.9	50	47.8	50	47.8
NO ₂	1-hr	209 ^b	75	284	-----	-----	564	50.4
	Annual	3.11 ^c	6	9.11	100	9.11	94	9.69
SO ₂	1-hr	94.85	35	130	-----	-----	1,300	10.0
	3-hr	47.22	26	73.2	1,300	5.63	-----	-----
	24-hr	23.89	11	34.9	365	9.56	262	13.3
	Annual	4.82	3	7.82	80	9.78	52	15.0
Pb	Quarterly ^d	0.00043	Not. Avail.	0.00043	1.5	0.03		
	90-day ^d	0.00043	Not. Avail.	0.00043	-----	-----	1.5	0.03

^a Concentrations are high-second high values except annual averages and SO₂ 1-hr, which is high-6th-high.

^b The ozone limiting method has been applied to this result.

^c The ambient ratio method has been applied to this result.

^d The 1-month average impact is used for compliance demonstration.

The annual modeled NOx impact was 4.15 µg/m³, which converts to 3.11 µg/m³ of NO₂ using the ambient ratio method. The maximum modeled 1-hour NOx impact was 212 µg/m³ which converts to 209 µg/m³ of NO₂ using the ozone limiting method.

CLASS I INCREMENT ANALYSIS AT NCIR

PM₁₀, SO₂, and NOx emissions were modeled using ISC-PRIME for the Class I (Northern Cheyenne Indian Reservation) Increment analyses. ISC-PRIME is the appropriate model for NCIR because it is located within 50 km of the proposed RME facility. Impacts at the Class I areas located farther from the site were modeled using CALPUFF.

The NCIR modeling results are shown in Table 6. All of the modeled impacts from RME were below Montana's proposed Class I SIL's. The Class I SIL's are all 4% of the associated Class I increment. The RME impacts are greatest at receptors on the western boundary of NCIR and drop with distance from the facility. The Department has determined that the RME project will not cause or contribute to a violation of a Class I increment based on the modeling results in Table 6. Therefore, cumulative modeling of increment-consuming sources is not necessary for this application. Because the modeled impacts are less than the Class I SIL's, the Department is confident that RME will not cause or contribute to a violation of the Class I PSD Increments.

Table 6: RME NCIR Class I Modeling Results (ISC-PRIME)

Pollutant	Avg. Period	Met Data Set	Class I Modeled Conc. (µg/m ³)	Montana Class I SIL ^a (µg/m ³)	Is RME Significant? (Y/N)	Peak Impact Location
PM ₁₀	24-hr	Hardin 2002	0.0814	0.3	N	(367925, 5059291)
	Annual	Hardin 2002	0.00378	0.2	N	(342474, 5044978)
SO ₂	3-hr	Hardin 2002	0.9861	1.0	N	(368820, 5059270)
	24-hr	Billings 1986	0.1176	0.2	N	(366931, 5059315)
	Annual	Hardin 2002	0.0097	0.1	N	(367031, 5059312)
NOx	Annual ^a	Billings 1984	0.0402	0.1	N	(367031, 5059312)

^a Class I SIL's found in Table 5.1 of Montana's Modeling Guideline

VISIBILITY ANALYSIS AT NCIR (VISCREEN)

NCIR is located within 50 km of the RME site, making short-range visibility impact analysis appropriate. RME estimated visibility impacts on NCIR following the methodology in EPA's Workbook for Estimating Visibility Impairment. RME submitted VISCREEN analysis to evaluate plume impacts on NCIR. All of the predicted plume impacts from RME's boiler were below the screening levels identified in the Level I VISCREEN analysis. No additional review of visibility impacts on the NCIR was needed.

CALPUFF MODELING FOR NOAB, AND UL BEND

RME submitted CALPUFF modeling to determine concentration, visibility and deposition impacts at the YNP, NOAB and UL Bend Class I areas. CALPUFF is the appropriate model

for receptors at distances greater than 50 km from the source. Guidelines for determining whether the Class I impacts were of concern came from the Federal Land Managers Air Quality Related Values Workgroup (FLAG) Phase I Report (December 2000). NRG submitted a refined CALPUFF modeling analysis on June 20, 2005. The Department reviewed the submittal and provided guidance for improving the analysis, including a request that NRG provide the impacts on each Class I area separately. NRG submitted a revised CALPUFF analysis on July 29, 2005. The revised analysis included RME-only concentration impacts for each mandatory Class I area. All the impacts were well below the Class I SIL's, so cumulative concentration impact analysis was not required. The Class I modeling report also included visibility analysis showing RME's peak impact at all three Class I areas. RME's impact was below the FLAG screening level of 5% change in background extinction range (ΔB_{ext}).

As part of the CALPUFF modeling review, the Department performed a CALPUFF screening analysis following the methodology developed by the Interagency Workgroup on Air Quality Modeling (IWAQM) (December 1998). The screening analysis used SAMSON data from the Billings NWS station, processed with upper air data from Great Falls. The results of the CALPUFF screening analysis confirmed that a refined, cumulative CALPUFF visibility analysis was not necessary.

The IWAQM CALPUFF screening methodology provides a highly conservative estimate of the impacts of the RME facility. The Department has used this methodology to determine that the RME impacts will not be of concern in the YNP, NOAB and UL Bend Class I areas.

The modeling results for RME's proposed ethanol project has demonstrated compliance with the NAAQS/MAAQS and PSD increments. Modeling has also shown that the project is not expected to have an adverse impact on AQRV's in Class I areas.

G. Unique, Endangered, Fragile, or Limited Environmental Resources

To identify any unique, endangered, fragile, or limited environmental resources in the immediate area of the proposed project, the Department contacted the Montana Natural Heritage Program of the Natural Resource Information System (NRIS), which catalogues species of special concern of the U.S. Forest Service, U.S. Fish and Wildlife Service; and Bureau of Land Management. The Natural Heritage Program files identified four species of special concern in the 1-mile buffer area surrounding the section, township, and range of the proposed facility. The four animal species identified were the *haliaeetus leucocephalus* (bald eagle), *heterodon nasicus* (western hognose snake), *sorex merriami* (merriam's shrew), and *sorex preblei* (preble's shrew). A bald eagle nest is estimated to be located approximately 1-mile north-northeast of the property boundary for the proposed RME site. A western hognose snake was sighted approximately 1.5 miles southwest of the proposed site. The sightings of merriam's shrew and preble's shrew are historic sightings (both dated 1884) located approximately 2 miles southeast of the proposed site. None of the species identified were located within the same section, township, and range of the proposed RME site.

As the facility site would be fenced, most terrestrials would stay away from the facility itself. In addition, the proposed site would probably not be a habitat area for animals as it had been an industrial site for some time prior to being purchased by RME. Although, as described in Section 7.B. of this EA, the impact on air quality would be moderate, the facility would not violate any ambient standards. The proposed facility would be required to operate in compliance with NAAQS and MAAQS, both primary and secondary standards. The secondary standards are applicable in this case, as they protect public welfare, including protection against damage to animal species.

To determine the impact on the bald eagle population, the Department consulted the U.S. Department of Interior, Bureau of Reclamation Montana Bald Eagle Management Plan (MBEMP). With the identified nest being approximately 1 mile away from the RME property boundary, the RME site would fall into a MBEMP “Zone III” Classification, representing home range for the bald eagles. Zone III is classified as the area from 0.5 to 2.5 miles in radius from the nest site (Zone II from 0.25 to 0.5 miles, Zone I from 1 to 1.25 miles). Zone III represents most of the home range used by eagles during nesting season, usually including all suitable foraging habitat within 2.5 miles of all nest sites in the breeding area that have been active within 5 years. The objectives in Zone III areas include maintaining suitability of foraging habitat, minimizing disturbance within key areas, minimizing hazards, and maintaining the integrity of the breeding area. The nest is located in a group of cottonwood trees located in the marshy area next to the Bighorn River. That area would remain unchanged by the facility operation, except for a possible moderate impact by air pollutants, as described in Section 7.F of this EA. The nature of the RME property would not change significantly, as it has been previously used as industrial property, and would continue to be used as such. In addition, the Cenex bulk storage facility is located between the sighted bald eagle nest and the RME facility. As discussed in Section 7.E of the EA, the noise associated with the project at 1 mile from the stack would be comparable to the sound of rainfall or a refrigerator humming. The nest atmosphere would probably not be disturbed by that level of noise, based on current levels of activity near the nest site.

RME would be responsible for compliance with any applicable statutes and regulations, including the Bald Eagle Protection Act, the Migratory Bird Treaty Act, and the Endangered Species Act.

The impact to unique, endangered, fragile or limited environmental resources from this project would be minor because the project would occur at an already disturbed site and would be minor in scope with respect to emissions increases. In addition, due to the plume characteristics from the proposed facility, the emissions would predominantly be carried to the north and east of the facility, away from the location of the plant species of special concern.

H. Demands on Environmental Resource of Water, Air, and Energy

As described in Section 7.B of this EA, impacts to the water resource would be minor because the demands for water (from the Bighorn River) would be insignificant compared with historical flow and the resulting amount of wastewater would be small.

As described in Section 7.F of this EA, the impact on the air resource in the area of the facility would be moderate because the amount and the type of air pollutants emitted and the good dispersion characteristics of the stack and the area. Ambient air modeling for NO_x, CO, PM, PM₁₀, SO₂, and VOC was conducted for the facility at “worst case” conditions and demonstrates that the emissions from the proposed facility would not exceed any ambient air quality standard. As a result of the ambient air quality analysis presented in Section 7.F of this EA, Permit 3402-00 would contain conditions limiting the emissions from the facility.

The impacts to the energy resource from the facility would be minor because the facility would consume relatively small amounts of coal in the coal-fired boilers. In addition RME would route emissions from the DDGS dryer and the DDGS cooler to the fluidized bed boiler for use as combustion air.

I. Historical and Archaeological Sites

The impacts on historical and archaeological sites would be minor because the site location contains no visible standing structures, the facility would physically impact a small amount of property, the facility would locate within an area that has been previously used for industrial purposes, and the site location is in an area that would likely not have been used for any significant historical or archaeological activity.

The area of the actual construction is located on the site of an unused sugar beet processing plant. As such, the area has been thoroughly disturbed by previous industrial activities. Due to the previous use of the site, if any historical structures once existed on the property, they would probably have been destroyed prior to or during the construction of the sugar beet plant processing facility.

The physical location of the site also indicates that it was not likely a location for significant historical or archaeological activity. The site location is located in the plains next to the river marsh area of the Bighorn River. The nearest portion of the Bighorn River to the site location is approximately 0.5 miles away.

The Department contacted the Montana Historical Society – State Historic Preservation Office (SHPO) in an effort to identify any historical, archaeological, or paleontological sites or findings near the proposed project. SHPO's records indicate that there are currently no previously recorded cultural properties within the project site. Because of the fact the industrial activities and land disturbances have occurred in the area, SHPO commented that the likelihood of finding undiscovered or unrecorded historical properties is practically nil. SHPO further commented "a recommendation for a cultural resource inventory is unwarranted at this time."

J. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from the proposed project on the physical and biological aspects of the human environment would be minor because the impact with respect to the already permitted (although not built) RME facility is very small. Any area sources that contribute to "background" levels of air emissions were included in the PSD increment modeling, mentioned in Section 7.F of this EA. As previously mentioned, the modeling analysis indicated that the emissions from the RME facility would not violate any Class I or Class II PSD increment or the ambient standards and would comply with the NAAQS/MAAQS.

Secondary impacts from this project on the physical and biological aspects of the human environment would also be minor. The proposed project may slightly increase the odors produced from the RME facility. Although possible odors from this proposed facility would be in addition to other odors common to the Hardin area (grain handling, vehicle exhaust, and industrial odors from the refinery), the cumulative and secondary impacts would be minor due to the small size and scope of the fermentation system project.

8. The following table summarizes the potential social and economic effects of the proposed project on the human environment. The "no action" alternative was discussed previously.

Potential Social and Economic Effects							
		Major	Moderate	Minor	None	Unknown	Comments Included
A.	Social Structures and Mores				X		yes
B.	Cultural Uniqueness and Diversity				X		yes
C.	Local and State Tax Base and Tax Revenue			X			yes
D.	Agricultural or Industrial Production			X			yes
E.	Human Health			X			yes
F.	Access to and Quality of Recreational and Wilderness Activities			X			yes
G.	Quantity and Distribution of Employment			X			yes
H.	Distribution of Population				X		yes
I.	Demands for Government Services			X			yes
J.	Industrial and Commercial Activity				X		yes
K.	Locally Adopted Environmental Plans and Goals				X		yes
L.	Cumulative and Secondary Impacts			X			yes

SUMMARY OF COMMENTS ON POTENTIAL SOCIAL AND ECONOMIC EFFECTS: The following comments have been prepared by the Department.

A. Social Structures and Mores

The proposed facility would not cause a disruption to any native or traditional lifestyles or communities (social structures or mores) in the area because the land use proposal would not be out of place given the previous land use of the area (including and surrounding the proposed site), and the fact that the greater surrounding area would remain agricultural and/or associated with the outskirts of the City of Hardin. The RME facility would be consistent with the former and current use of the larger area surrounding the facility (the former Holly Sugar processing plant, the current Cenex bulk storage facility, and the Rocky Mountain Power Plant).

B. Cultural Uniqueness and Diversity

The proposed facility would not cause a change in the cultural uniqueness and diversity of the area because the site was previously used for industrial activity (the Holly Sugar processing plant), and a Cenex bulk storage facility currently operates directly north of the proposed site. In addition, the Rocky Mountain Power generating station is currently under construction near the proposed site. Therefore, locating an industrial source such as RME in that area would not be "out of place".

As described in Section 7.F. of this EA, the project would not cause or contribute to a violation of ambient air quality standards. Therefore, unique cultures nearby (including the Tribe of Crow Indians and the Northern Cheyenne Tribe) would not be affected by this project. As the Northern Cheyenne Indian Reservation is a PSD Class I area, a Class I increment analysis was performed for that area. Based on that analysis and associated modeling results, the addition of RME to the area would not create a situation in which any increments would be exceeded. Therefore, RME would cause no change in the cultural uniqueness and diversity of the area.

C. Local and State Tax Base and Tax Revenue

The facility would have a minor effect on the local and state tax base and tax revenue because it would pay state and local taxes, and would employ numerous people (taxpayers) during construction and approximately 38 full-time employees after completion. In addition, the facility would provide value-added support for the area corn and barley price. The fuel grade ethanol and solid co-products would provide domestic alternatives for the area to replace petroleum-based gasoline and other animal feeds, respectively. The RME project would be privately funded.

D. Agricultural or Industrial Production

The proposed project would not result in a reduction of available acreage or productivity of any agricultural land; therefore, agricultural production would not be affected by building the facility. With respect to the usage of corn and barley in the ethanol production process, the facility would provide added support for the area corn and barley industries. Therefore, there would be some impact to the agricultural and industrial production.

E. Human Health

As described in Section 7.F of the EA, the impacts from this facility on human health would be minor because the emissions would be greatly dispersed before reaching an elevation where humans would be exposed. Also, as described in Section 7.F, the modeled impacts from this facility, taking into account other dispersion characteristics, are well below the MAAQS and the NAAQS. The air quality permit for this facility would incorporate conditions to ensure that the facility would be operated in compliance with all applicable rules and standards. These rules and standards are designed to be protective of human health.

F. Access to and Quality of Recreational and Wilderness Activities

The facility would result in a minor impact on the access to and quality of recreational and wilderness activities because the air emissions from the facility would be required to be in compliance with the NAAQS and MAAQS and would disperse before impacting the recreational areas (see Section 7.F of EA). The recreational activities in the area are approximately 1.5 to 3 miles away. Furthermore, the RME site is located on land previously used as an industrial site. The land use would not change. The property will continue to be private. No recreational or wilderness activities exist within the RME property boundaries. The RME facility would have no impact on the access to and quality of wilderness.

Recreational activities exist in the area surrounding the proposed site location. The closest recreational opportunity is the Arapooish fishing access point-recreation area (approximately 1.5 miles from the site).

G. Quantity and Distribution of Employment

The proposed project would have an impact on the quantity or distribution of employment at the facility or surrounding community. Approximately 38 industrial full time employees would be hired at the facility as a result of the project.

H. Distribution of Population

The proposed project does not involve any significant physical or operational change that would affect the location, distribution, density, or growth rate of the human population. Although approximately 38 full-time jobs would be created, it would not be enough to influx people into the area and cause the population to increase.

I. Demands of Government Services

The demands on government services would experience a minor impact. The primary demand on government services would be the acquisition of the appropriate permits by the facility (including local building permits, as necessary, and a state air quality permit) and compliance verification with those permits.

J. Industrial and Commercial Activity

The proposed project would allow RME to construct and operate a fuel-grade ethanol plant. The facility would represent a moderate increase in industrial activity in the area. The facility would operate 24 hours a day and 7 days per week producing ethanol. The level of activity associated with the RME facility would probably be similar to that of the Holly Sugar plant when it was operating. Other industrial activity in the area includes the Cenex bulk storage facility, just south of the RME site, and Rocky Mountain Power located in the same industrial park.

K. Locally Adopted Environmental Plans and Goals

The nearest nonattainment areas with respect to air quality are the Laurel SO₂ Nonattainment Area and associated SO₂ state implementation plan area (including Billings, approximately 45 miles to the west) and the Lame Deer PM₁₀ Nonattainment Area (approximately 46 miles to the east). Based on the air quality modeling performed, the RME project would not significantly impact either of those nonattainment areas and therefore, would have no effect on any locally adopted environmental goals and plans associated with those two areas.

The Department is unaware of any other locally adopted environmental plans and goals that would be affected by the facility or the other portions of the project as identified at the beginning of this EA.

L. Cumulative and Secondary Impacts

Overall, the cumulative and secondary impacts from this project on the social and economic aspects of the human environment would be minor because several new full-time employment opportunities would result; many construction related employment opportunities would be available.

The RME project would result in additional jobs for the Hardin/Big Horn County area. As described in Section 8.G of this EA, the facility would employ approximately 38 full-time people and numerous people during the construction phase. The “day-to-day” normal operation positions and the construction-related positions created by the RME project would bring additional money into the Hardin and Big Horn County economy.

Recommendation: No EIS is required.

If an EIS is not required, explain why the EA is an appropriate level of analysis: The proposed project is for the construction and operation of a fuel-grade ethanol plant to be located near Hardin, Montana. Permit #3402-00 would include conditions and limitations to ensure the facility would operate in compliance with all applicable statutes and regulations. In addition, there would be no significant impacts associated with this proposal.

Other groups or agencies contacted or that may have overlapping jurisdiction: Montana Historical Society – State Historic Preservation Office, Natural Resource Information System - Montana Natural Heritage Program, Montana Department of Revenue

Individuals or groups contributing to this EA: Department of Environmental Quality (Air Resources Management Bureau; Air, Energy, and Pollution Prevention Bureau; and Water Protection Bureau), Montana Historical Society – State Historic Preservation Office; Natural Resource Information System - Montana Natural Heritage Program; Department of Revenue

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Date: 7/21/05